Electric Feedback Forum
Office of Governor Martin O'Malley
Improving Maryland's Electric Distribution System

Roundtable Discussion #2: Undergrounding

August 27, 2012, 1:30pm – 4:30pm
President's Conference Room East 1 and 2
Miller Senate Office Building
11 Bladen Street
Annapolis MD, 21401

Executive Order 01.01.2012.15

List of Invited Participants

Jim Fama, Vice President, Energy Delivery, *Edison Electric Institute*

Matt Olearczyk, Senior Program Manager, *EPRI*

Philip DiDomenico, *Shaw Group*

Dr. Bilal Ayyub, Professor, *University of Maryland*

George E. Owens, President, *Downes Associates*

William M. Gausman, Senior Vice President, Strategic Initiatives, *Pepco*

Maryland Undergrounding Roundtable

Written Statement of
James P. Fama, Vice President Energy Delivery, Edison Electric Institute

August 27, 2012

Good afternoon, I am James P. Fama, Vice President, Energy Delivery for Edison Electric Institute. EEI is the association of U.S. shareholder-owned electric utilities. Our members serve 95% of the ultimate customers in the shareholder-owned segment of the industry and represent approximately 70% of the U.S. electric power industry.

Thank you for the opportunity to participate in this roundtable. I will offer some brief opening remarks.

The Pros and Cons Of Undergrounding

Over the years there have been many studies of undergrounding electric distribution lines. These studies show that undergrounding comes with many benefits but also presents several challenges. The most apparent benefit is the reduction in disruptions due to weather and vegetation. As we all know, vegetation is one of the leading causes of outages. Coupled with extreme weather, tree limbs and fallen trunks present the most imminent danger of outages. In dense urban areas, construction of underground lines is preferable where the logistics of overhead lines are impractical. Some aspects of maintenance are easier to manage as the facilities remain at ground level without necessitating poles and bucket trucks. Finally, the aesthetics of underground lines are more pleasing to the public and customers tend to be more accepting of these projects rather than new poles and lines altering or obstructing views.

However, undergrounding does pose significant challenges as well. Although undergrounding lines diminishes the harm caused by storms, flooding and uprooted trees can pose an outage threat to underground cables. Repair times and restoration generally take longer for underground cables with diagnostics becoming more complicated as linemen can no longer rely on visual inspection to locate and diagnose problems on the line. Underground facilities tend to be less flexible than overhead facilities when making upgrades or other system changes. Underground systems are still vulnerable to lightning and equipment failure.

The Cost Associated With Undergrounding

The biggest hurdle associated with undergrounding is its high cost. Costs for materials, construction, installation, replacement, and operation and maintenance of underground lines are all higher than that for overhead lines.

A 2008 EEI study showed that construction of new overhead distribution lines ranges from $53,000 (rural) to $386,000 (urban) per mile. Construction of new underground distribution lines is considerably higher, ranging from $63,000 (rural) to $2 million (urban). The study also showed that the cost of converting overhead lines to underground could be significant, ranging from $80,000 (rural) to $2 million (urban). However, the costs of conversion could range even higher, especially in larger urban areas, as the 2008 study is now four years old and furthermore utilized projections from utilities in low cost rural areas and mid-sized urban areas.

What States Have Done

Over the years, a number of states have commissioned studies to assess the viability and costs of undergrounding. The general consensus has been that converting existing overhead facilities to underground facilities is cost prohibitive compared to the benefits gained in terms of reliability. However, some states require utilities to underground lines in new residential subdivisions, which is becoming the industry norm. Some states have provided incremental cost recovery mechanisms in utility tariffs for customers that specifically request undergrounding of lines.

While a widespread conversion of the existing overhead infrastructure to underground facilities would be cost prohibitive, there is increasing support for "selective undergrounding." Some states have "selected" new residential and commercial distribution to be underground, absent exceptional circumstances. As earth-moving is already underway and disruption is minimal, undergrounding makes the most sense. Urban areas have also seen an increase in the use of undergrounding as a reliable option when overhead wires are not feasible. Priority for undergrounding is also being given to critical facilities when excavation is already underway in cases of sewer, water main, or roadbed replacement. Increasingly, states are providing consumers with the option to request undergrounding with varying mechanisms to collect the incremental costs. Going forward, utilities should evaluate their distribution networks to identify which structures have been most prone to outages and have proven more difficult to harden as possible candidates for selective undergrounding.

The Relative Cost-Effectiveness Of Undergrounding

There are a broad range of options for increasing distribution reliability, which can be divided into two broad categories: infrastructure hardening and resiliency measure. A hardening option would be a measure designed to strengthen your system to avoid an outage in the first place. Examples would include undergrounding or poles built to a higher design standard. A resiliency option would be a measure designed to shorten restoration time after an outage. Examples would include increasing the number of available crews or maintaining more spare equipment and materials.

All options, whether they fall into the hardening or resiliency categories, have their particular costs and their particular degree of effectiveness. For example, stronger poles may be cost effective and significantly increase reliability in Florida where hurricane winds can be strong. In contrast, undergrounding may be less effective when looking at cost and reliability in Florida because of the high water table and potential for flooding.

Electric customers are best served by a careful evaluation of the relative cost-effectiveness and reliability impact of the wide range of options, including undergrounding, with a goal of optimizing the mix of hardening and resiliency measures.

Maryland Undergrounding Roundtable

Recommendations of
James P. Fama, Vice President Energy Delivery, Edison Electric Institute

Short term:

- Evaluate the relative cost-effectiveness of selective undergrounding against (1) other hardening options, and (2) resiliency options (shortening restoration times).

- After determining cost-effectiveness, undertake selective undergrounding of outage-prone overhead lines that have proven difficult or impossible to harden in other ways.

- Evaluate and implement mechanisms for cost recovery of selective undergrounding.

Long term:

- Evaluate more extensive undergrounding as well as new and evolving technologies for their relative cost-effectiveness, taking into account the costs of more extensive undergrounding and integrating new technology with the distribution system.

- Evaluate the effect on reliability of more extensive undergrounding and integrating new technologies with the distribution system.

- Evaluate and implement appropriate mechanisms for cost recovery of more extensive undergrounding and new technologies.

Distribution Systems
Grid Resiliency

Matthew Olearczyk

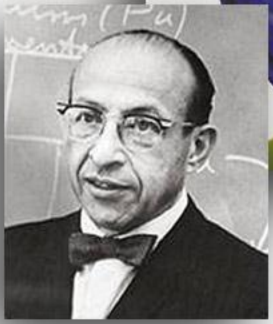
Senior Program Manager

Power Delivery and Utilization

August 2012

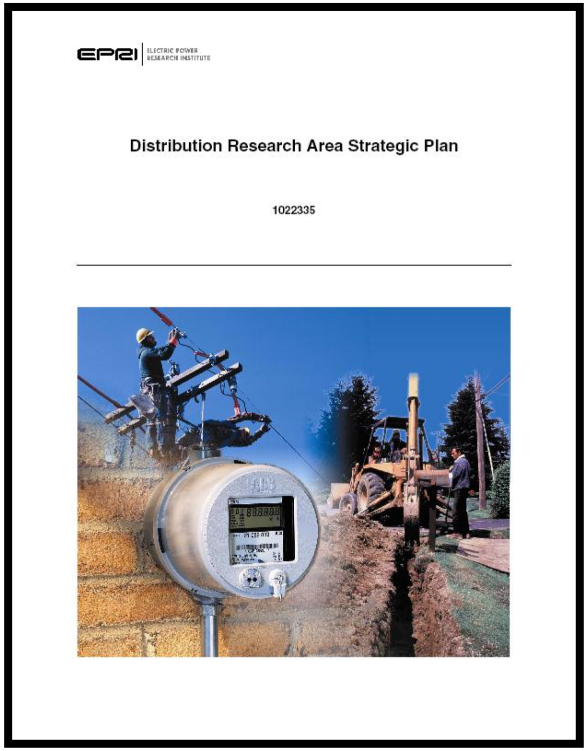
Our History…

- Founded in 1972
- Independent, nonprofit center for public interest energy and environmental research
- **Collaborative** resource for the electricity sector
- Major offices in Palo Alto, CA; Charlotte, NC; Knoxville, TN
  - Laboratories in Knoxville, Charlotte and Lenox, MA



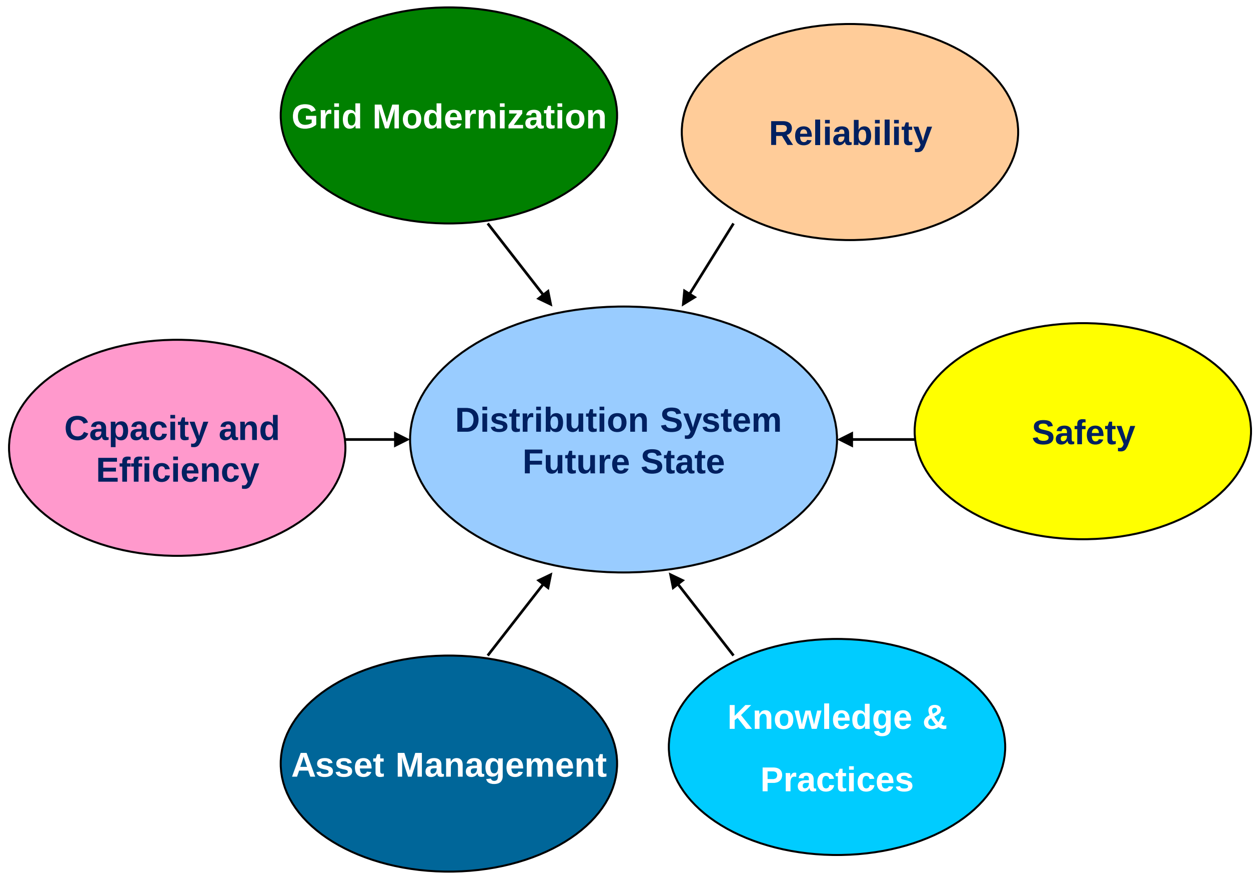
Chauncey Starr
EPRI Founder

EPRI Distribution Systems Strategy

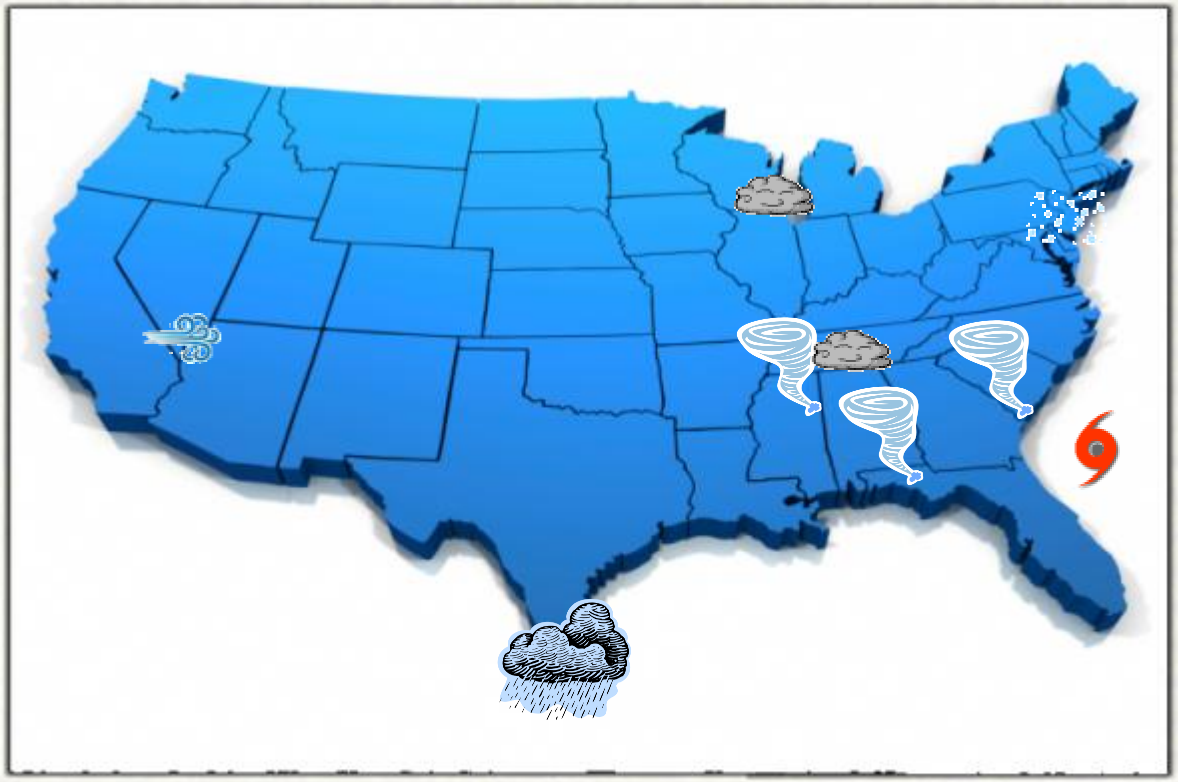

EPRI ELECTRIC POWER RESEARCH INSTITUTE

Distribution Research Area Strategic Plan

1022335



Major US Storms 2011



Customers Affected – Source: Department of Energy, Office of Electricity Delivery and Energy Reliability Summary 2011 Data

Late January 2011 ("Ground Hog Day" Storm) – Winter Storm, American Midwest, Southeastern US, New England, Northeastern Mexico, Great Lakes, Eastern Canada.
Customers Affected: ~1.4M

April 2011 – Tornados, Mississippi, Alabama, Georgia, South Carolina, North Carolina, and Tennessee.
Customers Affected: ~3.0M

June 2011 – Wind Storms, Tennessee, Illinois.
Customers Affected: ~1.1M

July 2011 – Straight-line windstorm, Chicago.
Customers Affected: ~0.8M

August 2011 – Hurricane Irene, East Coast.
Customers Affected: ~5.9M

October 2011 – Snow Storm, Connecticut, Massachusetts, New York.
Customers Affected: ~3.2M

December 2011 – Santa Ana winds, California.
Customers Affected: ~0.4M

Grid Resiliency – Resilient from what?

Physical Infrastructure

Information Infrastructure

Key to Resiliency: Prevention, Recovery, Survivability

Prevention: Now and Opportunity for Future Technologies

Vegetation Management

Selective Undergrounding

Pole and Line Design

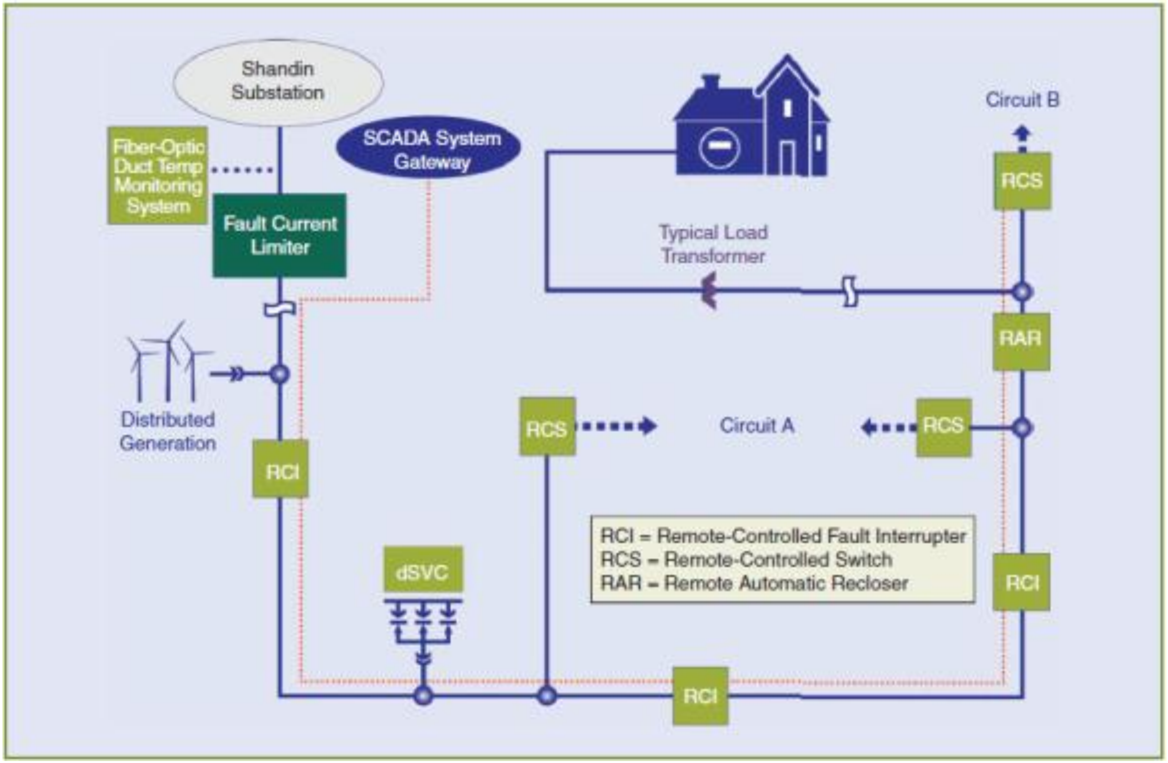
Hydrophobic Coating

Benefit/Cost for Each Option Needs to be Factored for Storm Hardening

Opportunities with Hydrophobic Coating

EPRI R&D Assessing Performance and Reliability of the Coating for T&D Application

Recovery: Circuit Auto-Reconfiguration



Courtesy: Southern California Edison

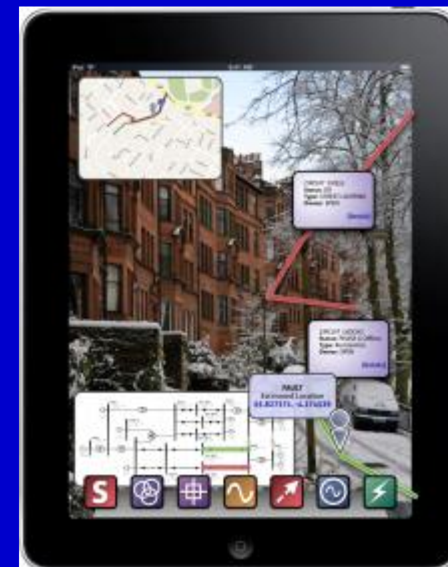
Sensors, Communication & Control

Advances in Sensor, Communication and Control Technologies Increases the Opportunity for Dynamic Circuit Reconfiguration

Next Generation Technologies for Improving Recovery

Using UAVs for damage assessment

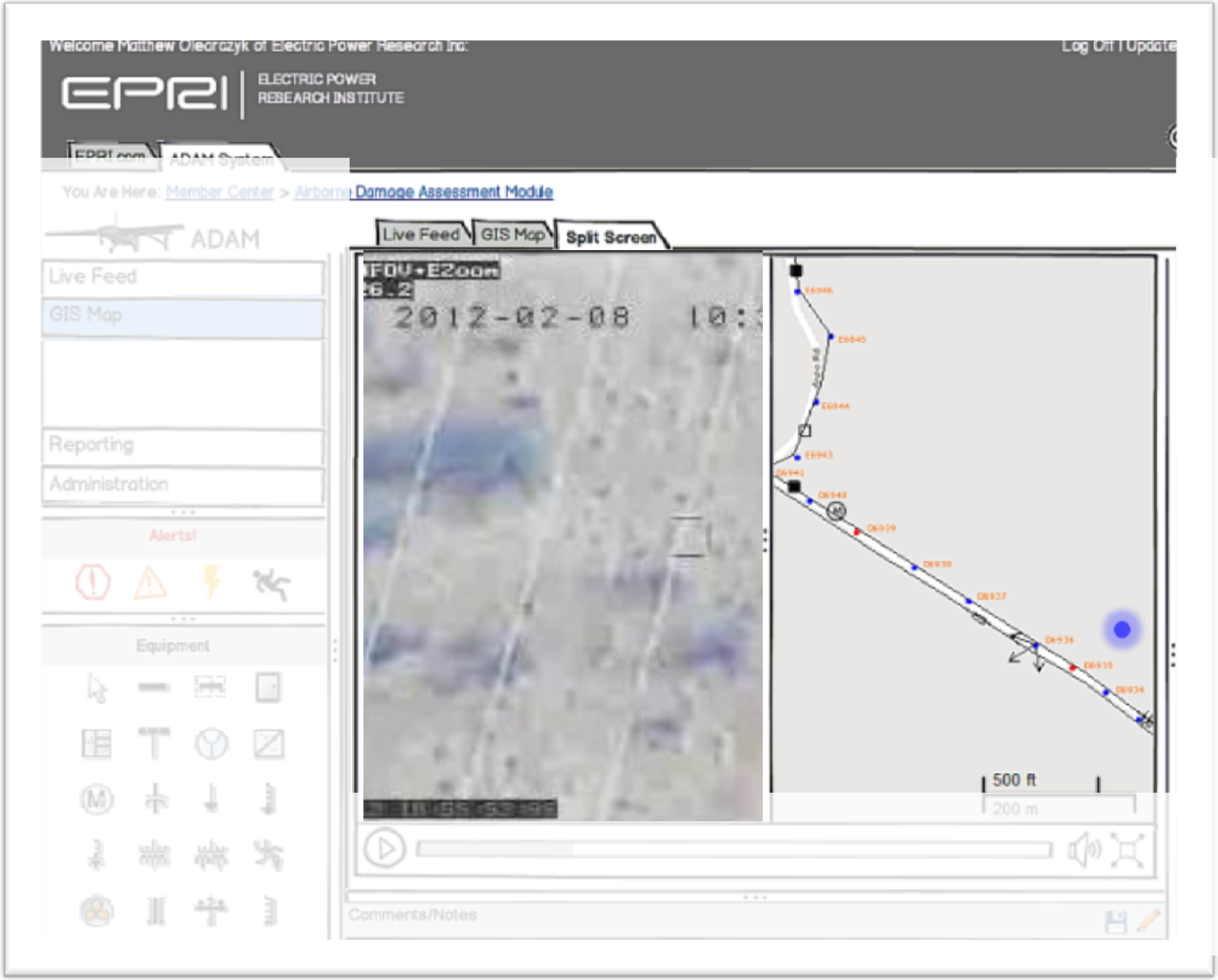
Integrating OMS and GIS with AMI systems



Enabling the field workforce

Leverage Damage Assessment Technology with Integrated Operational and Asset Information to Enable Faster Restoration

Airborne Damage Assessment Module Research



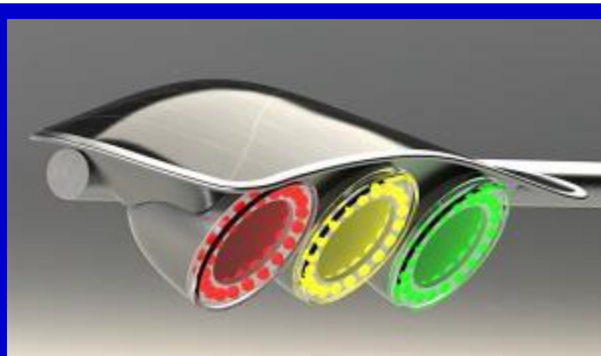
Evaluating UAV Platforms and Integration Need for Airborne Damage Assessment

Survivability: Leveraging New Technologies

EV Power Source

Courtesy: Nissan

Micro Grid



PV+Storage+LED Traffic Lights

Solar Chargers for Cell Phones

Continuation of Essential Missions even after the Grid has Failed

Courtesy: Carnegie Mellon Electricity Industry Center (CEIC).

In Conclusion… Distribution Grid Resiliency

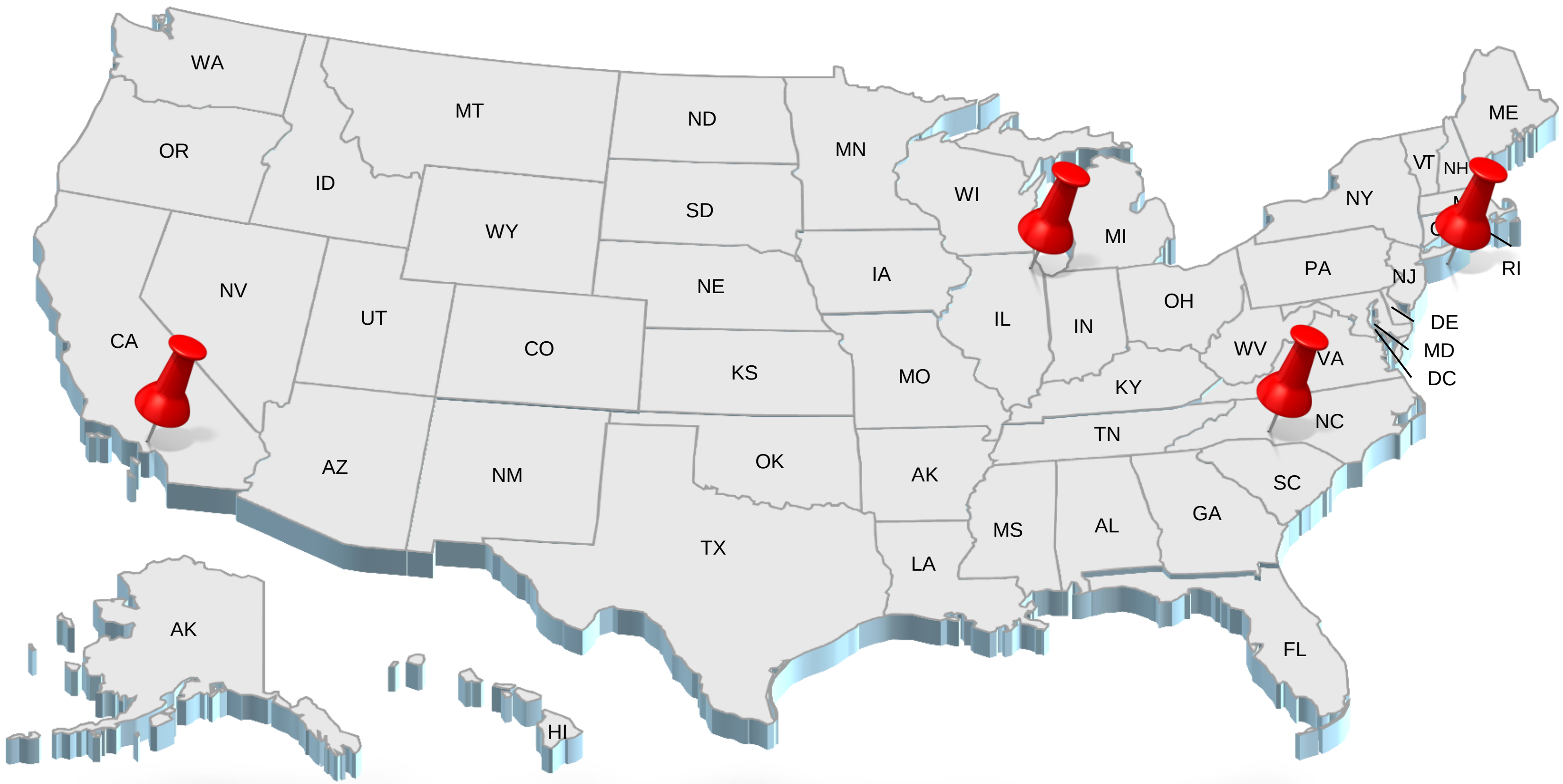
Prevention

Recovery

Survivability

Opportunity for Improving All Three Aspects of Resiliency Through Integrating New and Existing Technologies

Distribution Grid Resiliency Workshop Locations



Distribution Grid Resiliency

- Noteworthy Practices
- Infrastructure Damage Evaluations
- Vegetation Management
- Overhead Structure Hardening
- Underground Distribution Costing
- Smart Grid Impacts
- Hardening Prioritization & Storm-Response Investments

Together…Shaping the Future of Electricity

An Initial Literature Review

Undergrounding Electric Distribution Systems

DRAFT PAPER FOR DISCUSSION PURPOSES ONLY

2012

Presented by:

Matthew G. Olearczyk
Senior Program Manager

Distribution Research Area
(980) 939-4378
molearcz@epri.com

Electric Power Research Institute Inc.
1300 West W.T. Harris Boulevard
Charlotte, NC 28262

Table of Contents

Undergrounding

Undergrounding, or the conversion of overhead distribution networks to underground, is a hardening measure that is much discussed but only occasionally implemented. The benefits of undergrounding include increased protection from falling trees, ice, wind, and other storm damage; reduced vulnerability to vandalism; elimination of damage due to vehicular collisions; and aesthetic benefits, such as the removal of unsightly overhead wires from neighborhoods.

However, these are more than offset by the increased costs of underground infrastructure relative to overhead infrastructure; installation difficulties related to excavation and other actions necessary to place assets underground; more complex switching and control requirements; and increased time to locate and repair damage to underground lines. Further, in spite of wires being underground, other facilities such as feeder cables and substations are still above ground and therefore are susceptible to damage arising from storms or other weather related events.

Experiences

Following major storms, there has been renewed interest among public commissions, legislators, and customers in the value of an underground service. Because utilities in Western Europe and Japan undergrounded large expanses of their electrical system during the 1980s and 1990s, many amongst the U.S. public are questioning why U.S. utilities are not following suit.[1]

However, the European and Japanese processes were highly state-subsidized, either through grants or because many utilities were wholly or partially state-owned. Furthermore, most European nations and Japan do not have to concern themselves with the large distances that are commonly faced by U.S. utilities. Such distances generally make the mileage for undergrounding of complete distribution systems prohibitive; therefore, undergrounding assessments in the U.S. have largely focused on urban areas.

For example, due to the abundance of storms in the past 10 years, undergrounding investigations have been conducted by agencies in Florida,[2] [3] [4] [5] [6] North Carolina,[7] Maryland,[8] [9]

[1] ICF Consulting Ltd. "Overview of the Potential for Undergrounding the Electricity Networks in Europe." DG TREN/European Commission, 2003. http://ec.europa.eu/energy/gas_electricity/studies/doc/electricity/2003_02_underground_cables_icf.pdf

[2] Florida Public Service Commission, Report to the Legislature on Enhancing the Reliability of Florida's Distribution and Transmission Grids During Extreme Weather (Addendum to July 2007 Report), Jul. 2008.

[3] Quanta Technologies, "Undergrounding Assessment Phase 1 Final Report: Literature Review and Analysis of Electric Distribution Overhead to Underground Conversion," Florida Electric Utilities, Feb. 2007.

[4] Quanta Technologies, "Undergrounding Assessment Phase 2 Report: Undergrounding Case Studies," Florida Electric Utilities, Aug. 2007.

[5] Quanta Technology, "Undergrounding Assessment Phase 3 Report: Ex Ante Cost and Benefit Modeling," Florida Electric Utilities, Final Report, May 2008.

[6] L. Xu and R.E. Brown, "A Framework of Cost-Benefit Analysis for Overhead-to-Underground Conversions in Florida." Power & Energy Society General Meeting, PES '09. IEEE, 2009.

Louisiana,[10] Virginia,[11] Oklahoma,[12] Texas,[13] [14] and the District of Columbia[15] (See "Out of Sight, Out of Mind Revisited"[16] for a synopsis of many of these state studies). The general consensus has acknowledged the value of specific undergrounding; however, overall it has been agreed that undergrounding is simply too expensive in most situations.[17]

Survey of 50 State Public Service Commissions:

- None of the 40 responding commissions presently require undergrounding of existing power lines
- Six states (including D.C.) require undergrounding of distribution lines for all new residential subdivisions
  - Arizona, Maryland, D.C., Michigan, New Jersey, and New York
- In addition to these six states, municipal entities in six other states require undergrounding in new residential subdivisions
  - Missouri, New Mexico, Nevada, Utah, Washington State, and West Virginia
- In most cases, the incremental cost of undergrounding is paid by the customer that benefits, and/or the developer
- In some locations, such as Florida, Hawaii, and other coastal areas, undergrounding is proceeding based on storm-related reliability concerns, aesthetics, and benefits to tourism
- Several Commission staff report that undergrounding becomes an issue after a major storm event, but it is less of an issue once the high cost of undergrounding is determined

Source: Shaw Consultants International, "Study of the Feasibility and Reliability of Undergrounding Electric Distribution Lines in the District of Columbia," Public Service Commission of the District of Columbia, Formal Case No. 1026, Jul. 2010.

---

[7] "The Feasibility of Placing Electric Distribution Facilities Underground," Report of The Public Staff to The North Carolina Natural Disaster Preparedness Task Force, Nov. 2003.
[8] Exeter Associates, Inc., "Undergrounding Electric Utility Lines in Maryland," Dec. 1999.
[9] "Task Force to Study Moving Overhead Utilities Lines Underground," Dec. 2003.
[10] Louisiana Public Service Commission. Docket Search Page. Docket No. R-30821. [Online] https://p8.lpsc.org/Workplace/Search.jsp
[11] "Placement of Utility Distribution Lines Underground," Report to the State Corporate Commission, Jan. 2005.
[12] "Oklahoma Corporation Commission's Inquiry into Undergrounding Electric Facilities in the State of Oklahoma," Jun. 2008.
[13] Quanta Technology, "Cost-Benefit Analysis of the Deployment of Utility Infrastructure Upgrades and Storm Hardening Programs," Public Utility Commission of Texas Project No. 36375, Final Report, Mar. 2009.
[14] "Electric Service Reliability in the Houston Region," Mayor's Task Force Report, Apr. 2009.
[15] Shaw Consultants International, "Study of the Feasibility and Reliability of Undergrounding Electric Distribution Lines in the District of Columbia," Public Service Commission of the District of Columbia, Formal Case No. 1026, Jul. 2010.
[16] K. Hall, "Out of sight, out of mind revisited," in EEI Fall 2009 Trans. Dist. Meter. Conf., Kansas City, Oct. 2009.
[17] *Ibid*.

Advantages and Disadvantages of Undergrounding

A recent survey indicated that underground construction can be five to ten times the cost of overhead construction.[18] [19] In return, benefits include improved system reliability during normal weather, the potential for lesser storm damage and restoration costs, lower tree trimming requirements, and improved aesthetics.[20]

Potential disadvantages include higher maintenance and operating costs, longer duration interruptions, more customers impacted per outage, and environmental impacts. An analysis following a survey of 14 utilities conducted by the U.S. Department of Energy[21] noted that:

> *"Investor-owned utilities in North Carolina compared five years of underground and overhead reliability data, and found that the frequency of outages on underground systems was 50% less than for overhead, but the average duration of an underground outage was 58% longer."*

Advantages of Underground Facilities

In areas that are at risk from adverse weather, underground facilities are generally less affected by storm damage, wind damage, lightning damage, and ice build-up, resulting in a lower frequency of outage events. In areas where hurricanes and ice storms are an increasingly growing threat, undergrounding supplies reduce the number of customer outages and their associated restoration costs.

In many areas, installing underground cables is largely performed for aesthetic reasons, as a means of hiding unsightly equipment, and improving real estate values. Because utilities have to trim vegetation less frequently, this also lowers costs and reduces customer complaints that arise from aggressive tree trimming.[22]

Other significant advantages include improved community relations related to vegetation management, fewer motor vehicle accidents with utility poles, a reduced number of live-wire contact injuries, and fewer fires. Alongside the reductions in outage frequency, these advantages have a significant effect on community relations and corporate perception.[23]

Disadvantages of Underground Facilities

As a result of the extra time and complication involved with locating and repairing faults, undergrounding is not suitable for every area, especially low-lying coastal regions and river

[18] K. Hall, "Out of sight, out of mind revisited," in EEI Fall 2009 Trans. Dist. Meter. Conf., Kansas City, Oct. 2009.

[19] This figure is generally accepted in the literature, yet it is unclear if it relates to costs associated with new transmission lines, distribution lines, or a combination thereof.

[20] L. Xu and R.E. Brown, 2009.

[21] Office of Electricity Delivery and Energy Reliability, "Hardening and resiliency: U.S. Energy Industry response to recent hurricane seasons," U.S. Department of Energy, Aug. 2010.

[22] Tampa Electric. "Considering Underground Electric Service?," 2007. http://www.tampaelectric.com/data/files/UEService.pdf

[23] "Putting Cables Underground." Putting Cables Underground Working Group for the Commonwealth of Australia, Nov. 1998.

flood plains.[24] Although underground facilities are more resistant to storm damage caused by wind, debris, falling vegetation, and ice-storms, they are not impervious to such damage since they are susceptible to flooding, water intrusion, and storm damage. For example, the hurricane season in 2004 was particularly destructive in the state of Florida, where four major storms (Hurricanes Ivan, Charley, Frances, and Jeanne) uncovered and destroyed many underground power lines.

Damage to underground electrical systems from storms can extend beyond the immediate aftermath of the storm because water infiltration can cause corrosion and degradation that is not immediately apparent. Repairing cables weeks or months after the event creates extra disruption, detrimental to both customers and businesses.

Because most existing underground facilities are supplied from overhead sections of the grid, any damage incurred above will necessarily affect the performance of assets below ground. In addition, the connecting junctions between underground and overhead facilities are also susceptible to damage from weather, vegetation, animals, and vandalism, so any event causing an overhead outage will also cause outages on sections of underground facilities.[25] For example, after Hurricane Wilma struck Florida in 2005, 97%–98% of Florida Power and Light customers lost power supply, despite the fact that 54% were supplied by underground cables.[26]

Although underground systems are more resistant to vegetation damage, they can still be damaged by tree-root intrusion, which can physically damage conduits, trenches, and ducts, as well as allowing water ingress. In addition, falling trees during a storm can damage above-ground transformers and switch gear, and uprooted trees can tear through underground cables.[27]

The failure rates for underground cables increase significantly as they approach the end of their life, and locating and repairing faults is much more difficult than for overhead lines. A 2000 study by the Maryland Public Service Commission found that underground cables start to become unreliable after 15–20 years and reach the end of their service life after 25–35 years.[28] PEPCO found that customers served by 40-year-old overhead lines had better reliability than customers with 20-year-old underground lines.[29] Indeed, because of reliability issues, some utilities in Maryland have actually replaced underground lines with overhead lines.[30] Adding to the reliability issue, underground lines, after their installation, have a relatively high failure rate (relative to overhead lines) due to installation and quality issues, although this declines rapidly after 3–4 years of service.

[24] Quanta Technologies, Feb. 2007.
[25] K. Hall, 2009.
[26] Entergy. "Should Power Lines be Underground?," 2008. http://www.entergy.com/2008_hurricanes/Underground-lines.pdf
[27] "Putting Cables Underground," 1998.
[28] Exeter Associates, 1999.
[29] "Report to the Public Service Commission of Maryland on the Selective Undergrounding of Electric Transmission and Distribution Plant," prepared by The Selective Undergrounding Working Group, Feb. 2000.
[30] B.W. Johnson. "Out of Sight, Out of Mind?," Edison Electric Institute, 2006. http://www.woodpoles.org/documents/UndergroundReport.pdf

One of the reasons behind the higher maintenance costs compared to overhead systems is that it is more difficult to monitor and replace components on underground systems. Underground lines require specialized equipment and trained crews to isolate faults and repair systems. By contrast, a single lineman can conduct a visual inspection of an overhead line and conduct simple repairs, such as replacing a fuse. The extra equipment and labor can make underground maintenance in urban areas up to four times more expensive than for overhead lines.

Although undergrounding results in fewer motor vehicle accidents, there is the risk that workers can accidentally dig through cables, resulting in injury or death. In addition, workers need to enter underground vaults for maintenance, with the resulting risks of explosions, contacts, and arc flash burns.[31]

Cost Drivers

The cost-benefit analysis of undergrounding is extremely complex. In general, the average cost of overhead lines is reported as $10 per foot, whereas the average cost of underground lines is somewhere between $20 and $40 per foot.[32] Similarly, a report by the U.S. Department of Energy, following interviews with 14 utility companies, found that "*burying overhead wires costs between $500,000 and $2 million per mile, plus expenses for coolants and pumping stations.*"[33]

The discrepancies between many of the associated costs and benefits assessed by these studies are often attributed to the fact that they suffer from a lack of consistent methodology, as well as a small number of participants. In response to this, complex simulation tools, data models, and methodologies have been proposed, which include hurricane simulation, equipment damage assessment, restoration simulation, and cost-benefit analysis, e.g.[34] [35] [36]

There are two main cost drivers behind the added expense of installing underground systems, namely materials and labor. However, these costs vary significantly on a case-by-case basis, with a number of other factors influencing costs. Due to their variability, it is difficult to establish general undergrounding costs, but ballpark estimates vary between $500,000 and $4 million per mile of cable.[37] These estimates do not include the costs of moving telecommunications equipment from shared utility poles.

[31] R. Brown. "Literature Review and Analysis of Electric Distribution Overhead to Underground Conversion." *Infrasource Technology*, 2007. http://warrington.ufl.edu/purc/docs/initiatives_UndergroundingAssessment.pdf

[32] EEI. Underground vs. Overhead Distribution Wires - Issues to Consider. [Online]. http://www.eei.org/ourissues/electricitydistribution/Pages/Undergrounding.aspx

[33] Office of Electricity Delivery and Energy Reliability, "Hardening and resiliency: U.S. Energy Industry response to recent hurricane seasons," U.S. Department of Energy, Aug. 2010.

[34] T. Kury, "Evidence-Driven Utility Policy with Regard to Storm Hardening Activities: A Model for the Cost-Benefit Analysis of Underground Electric Distribution Lines," University of Florida, Department of Economics, PURC Working Paper, 2010.

[35] Quanta Technology, May 2008.

[36] S.A. Fenrick and L. Getachew, "Cost and reliability comparisons of underground and overhead power lines," *Utilities Policy*, 2011. doi:10.1016/j.jup.2011.10.002

[37] A collated summary of reported undergrounding costs per mile are provided in Table A of the Appendix, and show that the cost of conversion can range from an estimated $151,000–$3,500,000.

New Installation *vs*. Conversion: The cost of converting existing overhead systems to underground is higher than installing new systems. During conversion, the utility must build a new system while still operating the old overhead supply to ensure uninterrupted service, and then dismantle the overhead system once the switch is complete. As an example of how this adds to the overall cost significantly, Florida Power and Light (FPL) estimated that the cost of conversion consisted of 15% for dismantling existing systems, 65% for installing the underground components, and 20% for excavation.[38]

Other issues in mature urban areas include the disruption to homes and businesses while contractors dig up sidewalks and fences, and the potential need for landscaping upon work completion. Further, because utilities often share overhead poles, other service providers, including phone, cable, and internet providers, will need to make provisions for their cables, thereby potentially complicating the undergrounding process due to factors such as spacing requirements, trench/boring needs, and the installation of ground-level switching gear.

The difference in cost between new installations and conversions can be significant. FPL estimated that installing underground supplies for new developments costs between $1,685 and $2,491 per lot, as opposed to $1,223–$2,025 for overhead supplies. If a developer desires a main feeder line and pad-mounted switch cabinets, this can double or triple the differential. Due to this cost differential, many states are implementing legislation to make undergrounding mandatory for new developments, but they place no stipulations on utilities for converting existing overhead distribution circuits.

Redundancy: Because of the difficulties involved in locating and repairing faults in underground cables, many utilities incorporate redundancy and looped circuits, rather than radial designs. For example, LIPA, in a study performed by KeySpan Energy, attempted to estimate the extra costs of an undergrounding program. They found that the cost would be $5.5 million per mile for primary branch mains and $1.7 million per mile for primary branch lines. LIPA's costs are relatively high because the utility used looped designs, improving reliability but attracting higher installation costs.[39]

Area: Undergrounding costs vary between urban, suburban, and rural areas, with the laying of underground cables in rural areas cheaper per mile, though this is largely offset by the larger distances required for most rural distribution feeders. For example, figures reported in 2003 for the average costs encountered by three North Carolina utility companies indicated a near three-fold increase in costs in a suburban environment compared to rural. Man-hours worked may not be responsible for the entirety of this cost variation, given that they only differed by a factor of two between the two categories.[40]

[38] Florida Power and Light. http://www.fpl.com/faqs/underground.shtml

[39] "Economic Reliability Impact of Undergrounding the LIPA Distribution System", KeySpan preliminary report to LIPA, Feb. 2005. In Navigant Consulting Inc. "A Review of Electric Undergrounding Policies and Practices.´ *Long Island Power*. http://www.captivacivicassociation.com/html/undergrounding_utilities.html

[40] See Table C of the Appendix, "Average undergrounding costs (man-hours) per mile, reported by 3 North Carolina utility companies."

Within urban areas, costs can vary according to the density of population and the type of neighborhood. In older urban areas, the utility faces added complications regardless of whether boring or trenching is used for installing cables. Utilities have to avoid impacting other service providers, such as sewers, gas lines, water lines, and phone and cable conduits.

Urban areas carry their own restrictions during the undergrounding process. Local statutes may restrict the number of allowable hours worked per day, and may place extra restrictions on the amount of heavy equipment used due to noise reduction measures. Traffic controls or measures to allow access to local businesses are another potential complication, increasing labor costs significantly.

According to EEI, when compared to a typical cost of $120,000 per mile for overhead construction, undergrounding costs range from $500,000 per mile in California to $1,826,415 for PEPCO. This cost can be attributed to differing land topographies, and to the need for manholes, vaults, and duct banks in the Washington D.C. metropolitan area.[41]

Securing Easements and Right of Way: Obtaining easements can be difficult, especially for pad-mounted transformers and other above-ground equipment. This is much more of a problem in urban than rural locales, where a utility may have to obtain easements from many individual property owners. This process is both costly and time-consuming, so utilities set aside extra resources to cover the legal and procurement issues.[42]

Problems of Installation in Aged Systems: In urban areas, trying to rejuvenate or connect new underground runs to older systems can create a number of problems. Older vaults or concrete poured into duct banks without forms means that contractors face more work in clearing and preparing the work site. The problem of avoiding impacting other service providers, mentioned above, also exacerbates the complexity of planning and designing underground systems relative to overhead systems. Unfortunately, older urban areas often lack accurate utility maps and plans, making surveying difficult.

Cable Type: From the different conditions encountered in underground distribution circuits, underground cables need to possess a different range of attributes than do overhead cables. For underground cables to carry the same load as overhead cables, they usually have to be of a significantly larger diameter due to issues with high capacitance and leakage. Most utilities are looking at newer cable types, shown to reduce losses by almost 25%. U.S. utilities prefer to use LLDPE cable, because it is more resistant to corrosion and the formation of water trees.[43]

High capacitance is common with underground cables, largely because the cables are closer to each other and to the earth, and this causes current to flow even when the cable has no connected load. Depending upon line voltage, longer lines can have 20–75 times the charging

[41] Navigant Consulting Inc., Feb. 2005.

[42] Virginia State Corporate Commission. Placement of Utility Distribution Lines Underground," Report to the State Corporate Commission, Jan. 2005.

[43] D.E. Griffiths and R.S. Jassal. "Selecting the Right Cable for the Network." 4th PPA Engineer's Workshop, Aug. 2008. http://storage.baselocation.com/olex.co.nz/Media/Docs/Microsoft-Word-Selecting-the-right-cable-for-the-network-Tech-Paper-for-P-47d32910-9650-4519-93e2-09ef8ef3b36c.pdf

current of an overhead line, limiting its ability to deliver power, especially over longer distances.

Soil Type & Vegetation: Soil type[44] is a major issue that dictates the course of underground cables, as well as the complexity of trenching and backfilling. In rural areas, erosion is a concern, so the utility must ensure that the soil layers are not mixed and that the topsoil is replaced last, in order to allow better landscaping. If a different type of backfill is used to fill trenches, this can affect the vegetation and farming practices.

In North Carolina, soil conditions vary as the terrain moves from the mountainous regions to the coastal areas. Mountainous areas can add to the costs significantly since they sometimes mean that a utility has to dig trenches in solid rock, wetlands, high water tables, and crossing rivers.[45]

Undergrounding reduces the necessity for vegetation management, and therefore the costs of such endeavors (though it does not eliminate them). The current costs involved in, e.g., tree trimming, can account for between $570–$12,245 per mile,[46] with the large variation dependent upon the particular landscape and topography involved.

Backfilling: The thermal conductivity of the surrounding soil is crucial when backfilling trenches. Unlike overhead cables, which use air to carry away heat, underground cables rely upon the surrounding soil, which dissipates all of the heat from the cable (quantified by the soil thermal resistivity, °C-cm/W). During the design stages, a utility may have to perform a soil survey to determine the heat conductivity characteristics of the inhabiting soil since a sandy variety will dissipate the heat generated better than more saturated soils, possibly leading to the use of a different backfill material to ensure sufficient heat transfer.[47]

Pipe-type conductors operate at between 167°F and 185°F, with an emergency operating temperature of 212–221°F. XLPE conductors operate at higher temperatures (between 176°F and 194°F), with an emergency operating temperature of 266°F. This heat must be carried away by the soil if the conductors are to perform optimally, so higher voltage lines often require coolants which provoke environmental concerns. For this reason, many utilities are focusing on water-based systems rather than oil-based coolants.[48]

The use of coolants was exemplified when Seattle City Light found that its distribution system had a number of thermal bottlenecks in its conduit banks, so it could not install cables of

[44] The dominant soil orders, each with different physical characteristics, vary by state, with some scattered nationwide (e.g., alfisols, which make up ca. 14% of the entire surface area of the U.S.), and others densely packed within a particular locale (e.g., spodosols, which are found in Florida and the northeastern states). http://soils.usda.gov/technical/classification/orders/

[45] Report of the Public Staff to the North Carolina Natural Disaster Preparedness Task Force, Nov. 2003.

[46] Based on a limited sample of data. For a summary, see Table B, "Summary of reported vegetation management costs", in the Appendix.

[47] G.S. Campbell and K.L. Bristow. Underground Power Cable Installations: Soil Thermal Resistivity. *Decagon Devices, Application Note*, Jul. 2007.

[48] Public Service Commission of Wisconsin. "Underground Electric Transmission Lines." Electric 11, 2011.

greater ampacity than 310 A per cable in a 72 duct bank of 13 kV cables. The utility isolated the poor conduction of heat due to high cable density as the problem, so it installed four water-cooling pipes above its duct banks, improving conductivity and allowing them to increase the maximum ampacity by 60%.[49]

Site Restoration: As with overhead systems, the utility must restore the site to as close to its previous condition as possible, but this can be much more complex for underground systems even if boring is used as opposed to trenching. Roads and landscapes must be returned to their original condition, as must other infrastructure, including driveways, fences, and curbs. In easements, yards and farmland should be restored using the topsoil stockpiled during the operation. Local statutes exist to protect landowner's rights in this regard.

Cost Estimations

In 2006, EEI estimated that burying overhead power lines costs approximately $1 million per mile, ten times greater than for installing overhead networks. A 2007 study by Entergy, prompted by the Public Utility Commission of Texas, agreed with this cost differential, estimating that it would cost $5 million to install underground circuits, as opposed to $500,000 for standard overhead installations. However, this study was for transmission systems, which are more difficult to install underground.[50]

In terms of rate increases and extra costs to the customer, a series of state-initiated studies explored these outcomes. In 2005, the Virginia State Corporation Commission estimated that undergrounding would cost at least $3,000 per customer and that the benefits of a state-wide undergrounding project would offset only 38% of the total extra costs.[51]

A 2002 North Carolina study and a 2003 Florida study supported this data, showing that the rate increases required for undergrounding distribution lines would need to be between 80% and 125%. Because of the sheer number of variables affecting the costs of underground distribution, it is difficult to break down estimates into their individual elements, as shown by the wide differences in the various state reports. The costs for undergrounding are generally only applicable on a case-by-case basis, with previous studies only giving broad guidelines.

New Technologies and Cost Savings

New technologies have the potential to reduce costs of underground distribution infrastructure and services. Much public policy already dictates installation of underground electricity delivery to new developments and urban neighborhoods; therefore, this requirement may drive future advances in new technologies for undergrounding.

[49] B. Tobin, H. Zadehgol, K. Ho, G. Welsh and J. Prestrud. "A Water Cooling System to Improve Ampacity in Underground Urban Distribution Cables." Seattle City Light, 2006. http://www.scribd.com/doc/26762335/A-Water-Cooling-System-to-Improve-Ampacity-in-Underground-Urban-Distribution-Cables-1

[50] Entergy. "Should Power Lines be Underground?," 2008. http://www.entergy.com/2008_hurricanes/Underground-lines.pdf

[51] Ref. 23 drew a similar conclusion, with an even lower claw-back rate reported of just 11% of total costs.

Boring and Trenching: For many undergrounding projects, trenching has been the preferred method of installing underground distribution systems. Apart from the ease of excavation, especially if 'plowing' is used, they are a low-tech solution. However, traditional trenches carry a number of problems, mainly caused by disruption to businesses and homes; high labor costs for digging and backfilling; restoration and landscaping costs; and the issue of trenches sinking and leaving potholes as the substrate settles under the weight of traffic.[52]

As is often the case with overhead poles, working with other service providers on multi-use infrastructure can reduce costs and minimize disruption. Sharing trenches will reduce installation and maintenance costs, and reduce customer disruption. However, there are a number of technical, safety, and regulatory barriers to overcome, so developing multi-use trenches is not common, as yet, with electricity and telecommunications preferring to excavate their own trenches.[53]

One maturing technology that is addressing these issues, and finding particular use in urban areas, is horizontal directional drilling (HDD). Modern directional drills are compact, track-mounted, and completely self-contained, with their small size meaning that the equipment can access restrictive spaces. The drill pipe is carried on a cartridge mechanism, allowing crews to set up the equipment at the drill site and lay cables in a much shorter time than is possible with traditional techniques. Modern units have very high thrust and pullback capabilities, ensuring that they can operate through most soil types.

One issue that was traditionally faced by boring units was the problem of harder substrates and rocky soils, which can double or triple the drilling costs. Modern units are robust and incorporate 'Bear Claw' bits with carbide-tipped teeth, ensuring that contractors do not need to bring in larger, more powerful, HDD units or use bentonite drilling fluids. However, some of the larger rigs weigh between 30,000 and 40,000 lbs., making them too large and unwieldy for many urban areas.

For example, Edmond Electric[54] used 5,000 lb. drilling rigs in an area notorious for difficult drilling conditions, yet these small machines could enter standard yard gates and driveways, without causing damage. The utility used slightly larger, 10,000 lb. machines for heavier tasks. The new technology included better drilling fluids and a wider selection of tools that decreased the number of bore failures. Further, using standard HDD guidelines, contractors were able to drill more accurately and quickly, increasing productivity and lowering labor costs.

Thermal Conductivity Improvements: Because of the rapidly increasing demand for power, utilities are trying to increase the amount of electricity flowing through ducts and trenches. As a result, thermal conductivity is becoming a major bottleneck to undergrounding projects. In many cases, concrete slurry is used to surround cables, but some utilities are considering 'slack

[52] S. Wirsching. "Trenchless Burial Equipment," Oct. 1999.
[53] "*Putting Cables Underground Working Group Report.*" Commonwealth of Australia Finding 17, 1998
[54] See case study, Page 14.

wax' for high load cables. This substance, a readily available by-product from oil-refining, can be added to backfill to fill the gaps between particles and act as a barrier to heat transfer.[55]

New Cable Technologies: New cable technologies, such as IMPB cable, are reducing the costs of installing underground systems. Although the cable is more expensive to purchase than traditional cables, it does save money in other areas. Firstly, because these cables have better abrasion resistant properties and have less capacitance, they can be packed more closely. By reducing the amount of backfill needed, it means that trenches and conduits can be narrower, and the fact that less filling material is required to bed the cables means that there is no need for storing or moving large quantities of soft sand.[56]

The U.S. government has invested $30 million for the development of superconductive HTS cable technology, mainly for transmission networks but also for high-voltage distribution applications. The superconducting cables reduce power losses from 5–8% to less than 1%, and the HTS cables can carry ten times the amount of power as the same thickness of copper cables. It is hoped that, although the cables are initially expensive, they will meet the demands of heavily populated areas and allow for high voltage transmission and distribution, reducing the need for transformers. Currently, the cable costs $200 per kAm (kiloampere meters), as opposed to $10 for copper cabling, but this is set to fall to $50 per kAm with economies of scale. The target is to achieve parity with copper wire prices.

Some companies have started to trial the new cable types. In December 2002, Southwire and NKT Cables, in a joint venture called ULTERA, produced a 300 meter HTS cable for installation in Columbus, Ohio. This three-phase system not only reduces the amount of superconducting material required, but also reduces the amount of space needed for installation, lowering labor costs significantly.[57]

Robot maintenance: Although many utilities are improving the use of sensors within their underground systems as they develop preventative maintenance programs, these cannot cover every single area of an underground network. Mobile maintenance robots may be the key, allowing utilities to monitor underground duct banks and conduits more easily and at lower cost. However, research is only at the prototype stage, and there are many issues with space restrictions, different cable types, and the miniaturization of equipment.[58]

Cost Sharing

New technologies and techniques are major factors in reducing costs, but utilities are also looking at other ways of reducing the investment in undergrounding. One way is to target undergrounding procedures at specific areas to maximize return on investment. In addition,

---

[55] M. Rabinowitz. "Advanced Power Transmission of the Future." Armor Research, 2003. http://arxiv.org/ftp/physics/papers/0304/0304070.pdf

[56] F. Charles, R. Petreus and P. Argaut. "New Approach for MV Underground Connection." JICABLE ' 03 - International Conference on Insulated Power Cables, 2003. http://www.sileccable.com/Portals/france/pdf/fr/2251_Jcab.pdf

[57] ICF Consulting Ltd, Overview of the Potential for Undergrounding the Electricity Networks in Europe, Feb. 2003.

[58] B. Jiang. Mobile Monitoring of Underground Cable Systems." Thesis submitted to the University of Washington, 2003. http://www.ee.washington.edu/research/seal/pubfiles/MSEE_bing.pdf

most utilities are cooperating with state and federal bodies, seeking grants, rate recovery, or cost sharing. Finally, by working with local communities and other utilities, costs can be shared amongst a number of stakeholders.[59]

In Ocean City, Maryland, utilities and town authorities have adopted a cost effective approach to undergrounding, one which shares costs and reduces the impact by using a single, unified plan rather than a piecemeal approach. If the plans submitted by utilities for undergrounding projects are passed, the municipality installs the conduits, manhole covers, pad mounts, and customer equipment, drawing upon General Obligation Bonds for funding. After the utility has installed the equipment and de-energized the overhead lines, the town performs all of the restoration and landscaping.[60]

Edmond Electric – A Case Study [61]

Edmond Electric, a municipally-owned electric utility in Edmond, Oklahoma, investigated the feasibility of converting overhead distribution systems to underground. Alongside the extra cost, the project attracted concerns from residents, primarily related to the disruption that would be caused by digging up streets and private property. Despite these concerns, the utility decided that the benefits of undergrounding far outweighed the costs.

Edmond Electric decided to test the process on smaller areas, concentrating on neighborhoods that possessed old overhead infrastructure with the associated high maintenance costs and reliability issues. One such area, Henderson Hills, had 50-year-old equipment and a high level of outages, mainly caused by rotting poles and structural damage from a previous ice storm. In addition, many residents complained that the vegetation management was too aggressive and destroyed the aesthetics of the area. In total, 500 residents were converted to underground supplies, and the utility plans to continue with this incremental approach, allowing them to gather data on the process and refine their approach.

Edmond Electric decided that community relations were one of the most important aspects of the project, so the company decided to use HDD technology to install the conduits. For this, the utility's external contractor, Doyle Webb Inc., used 'Ditch Witch' units, with the process cost significantly less than trenching the underground lines.

Doyle Webb installed 18,300 ft. of conduit in the area, with very little trenching. The utility made sure that accessibility for future repairs was included within the initial designs by using modern HDPE Schedule-40 conduit, which also allows for future changes to design and load increases. Edmond Electric included redundancy within the design, allowing the easy rerouting of power supplies in cases of cable failure or damage. A fault in one of the lines, caused by manufacturing defects, was repaired in 30 minutes, suggesting that this attention to accessibility is paying off.

[59] Navigant Consulting, Feb, 2005.
[60] *Ibid*.
[61] D. Sherrick. "Overhead to Underground Conversion in Oklahoma." Transmission and Distribution World, Aug. 2004. http://tdworld.com/mag/power_overhead_underground_conversion/

Public relations were an important part of the project, as the utility ensured that customers were aware that the short-term inconvenience would lead to longer-term improvements in terms of reliability and aesthetics. Public consultations allowed concerns to be addressed long before the first rigs hit the streets, and using a local contractor with a long history of working alongside the utility also helped to engage the public.

One issue isolated by the utility was the cost of meter replacements, which were originally the responsibility of residents. Some residents chose not to pay for upgrades, so they were given short poles instead. Edmond is investigating whether it should absorb these costs next time, by using a single contractor for installation and negotiating lower process. Installing the short poles incurred extra labor costs and crews often found themselves waiting for independent electricians to complete meter installation, holding up work. Another issue was the lack of integration with other utilities: for future projects, Edmond intends to engage with telecommunications companies and look into the possibility of joint boring by installing two conduits into a single bore hole and sharing the project costs.

Note on O&M Costs

Very recent research[62] suggests that power outages and the greater reliability that stems from undergrounding may have more of an impact on operational and maintenance (O&M) costs than was previously thought. As mentioned above, it is commonly understood that underground facilities incur marginally greater O&M costs than their overhead counterparts, based upon an increase in non-trimming and non-vehicular accident liabilities. Of course, the validity of this statement depends on how one categorizes the constituents of such overall costs. Generally, and in keeping with the lack of consistent study methodology employed in the available literature, such costs are reported with minimal clarification, but mostly include consideration of day-to-day service restoration, and mostly exclude costs associated with vegetation maintenance. Reported data by Old Dominion Power Company illustrate that O&M costs for underground distribution facilities are "significantly higher than for overhead facilities."[63] Further studies also report that underground and overhead O&M costs are comparable and that no significant reduction in O&M costs would be derived from undergrounding.[64]

However, modeling studies[65] (double-log O&M cost model) carried out on a dataset from 163 U.S. electric utilities, conclude that doubling the current percentage of undergrounding at each utility would lower O&M expenses by ca. 4.4%. To put this number in perspective, the average O&M costs described by three North Carolina utilities in 2003 were $920 and $4,052 per mile for underground facilities that were direct buried and urban duct bank-based, respectively.[66] These data were calculated based on the costs of maintaining 20,629 miles of underground

[62] S.A. Fenrick and L. Getachew, 2011.
[63] Report to the State Corporate Commission, Jan. 2005.
[64] Report of the Public Staff to the North Carolina Natural Disaster Preparedness Task Force, Nov. 2003.
[65] S.A. Fenrick and L. Getachew, 2011.
[66] Report of the Public Staff to the North Carolina Natural Disaster Preparedness Task Force, Nov. 2003.

assets. At this juncture, it is perhaps a worthwhile reminder that all costs associated with undergrounding are very much dependent upon each particular project and its circumstance.

Conclusions

Consensus in the literature places the cost of undergrounding electrical distribution assets at 5–10 times more expensive than overhead construction.[67] Data summarized in the Appendix of this report illustrate that conversion costs vary widely, ranging from an estimated $151,000 to $3,500,000 per mile. The drivers that contribute to these costs include having to maintain two networks while construction is underway; redundancy of circuits; the securement of easements and rights of way; boring and trenching; operation and maintenance costs; and site restoration. Within this mix lie numerous factors that complicate the calculation of overall costs, including the soil type encountered during excavation, the cable type used, and the type of area that requires conversion. For example, conversion costs vary between urban, suburban, and rural areas, with a possible three-fold cost difference between the two latter locales.[68]

Of course, there are also benefiting factors to undergrounding, and these include reduced tree-trimming costs; reduced costs arising from vehicular accidents; and avoided impact from outages and storms. Taking tree-trimming as an illustrative example, current reported costs associated with this action range from $570–$12,245 per mile trimmed, thus representing respectable opportunity for cost savings.[69] Further savings are also expected from the impact of advanced undergrounding technologies, such as horizontal directional drilling; improvements to thermal conductivity and cabling; and through carrying out maintenance through automation. Advances in the first of these have been proven to reduce costs compared to trenching through the use of machines such as 'Ditch Witch' units.[70]

Despite the cost, and mixed cost-benefit analysis, the available data have demonstrated that utilities are investing significantly in the construction of new underground facilities, spending about 26% of distribution dollars annually on underground construction.[71] Studies have shown that utilities see the value in, and are open to, targeted undergrounding of their overhead facilities, particularly for facilities serving critical infrastructure, rear lot circuits, and selected backbone circuits.

Underground lines are not the perfect solution to reliability issues, and the extra costs and rate increases more than outweigh the benefits in many situations. The lower frequency of outages is offset by their longer duration, and their (often) higher maintenance costs offset savings in other aspects, such as vegetation management. However, the aesthetic qualities make them an attractive proposition for new developments, especially where easy access and redundancy can be installed at little extra cost.

- - -

[67] K. Hall, 2009.
[68] Report of the Public Staff to the North Carolina Natural Disaster Preparedness Task Force, 2003.
[69] see Table B in the Appendix.
[70] D. Sherrick, 2004.
[71] K. Hall, 2009.

Appendix

Table A. Summary of costs ($, per mile) for conversion of overhead to underground distribution lines.

Year	State	Cost	Estimated or Actual cost	Project Info.	Reporting Ref.
1996	FL	917,532	Actual	Sand Key	[4]
1999	MD	350,000	Est.	Min. cost	[9]
1999	MD	2,000,000	Est.	Max. cost	[9]
2000	MD	952,066	Est.	BGE	[9]
2000	MD	1,826,415	Est.	PEPCO	[9]
2000	MD	728,190	Est.	Conectiv	[9]
2000	MD	764,655	Est.	Alleghany Power	[9]
2000	FL	414,802	Actual	Allison Island	[4]
2003	NC	3,000,000	Est.	Max. cost	[7]
2003	NC	151,000	Est.	Min. cost	[7]
2003	MD	450,000	Est.		[9]
2005	VA	1,195,000	Est.	Av. cost	[11]
2006	DC	3,500,000	Est.	Extrapolated from 1 feeder	[15]
2006	mult.	1,006,491	Est.	Av. cost	[30]
2006	FL	814,929	Est.	State of Florida	[72]
2006	NY	1,578,976	Est.	LIPA	[39]
2006	CA	1,191,176	Est.	Tahoe-Donner	[73]
2006	VA	950,000	Est.	Virginia Power	[7]
2006	CA	500,000	Est.	State of California	[74]
2006	FL	840,000	Est.	Florida Power & Light	[75]
2006	GA	950,400	Est.	Georgia Power	[76]
2006	WA	1,100,000	Est.	Puget Sound Energy	[30]
2006	FL	883,470	Actual	County Road 30A	[4]
2006	FL	1,686,275	Actual	Pensacola Beach	[4]
2008	OK	1,500,000	Est.	Av. main lines	[12]
2008	OK	500,000	Est.	Av. lateral lines	[12]

[72] Florida Public Service Commission, "Preliminary Analysis of Placing Investor-Owned Electric Utility Transmission and Distribution Facilities Underground," Mar. 2005.
[73] CVO Electrical Systems, "Undergrounding Feasibility Study for Tahoe Donner Association Truckee, California," Feb. 2006.
[74] Utility Undergrounding Programs, Scientech, May 2001, p21.
[75] *Ibid,* p30.
[76] *Ibid,* p42.

Table B. Summary of reported vegetation management costs ($ per mile).

Year	State	Company	Miles trimmed	Cost	Ref.
2008	FL	FPL	6,669	9,777	[2]
2008	FL	PEF	4,315	4,548	[2]
2008	FL	TECO	1,308	7,875	[2]
2008	FL	GULF	2,553	570	[2]
2008	FL	FPUC	90	5,861	[2]
2008	TX	TNMP	5,666	6,133	[13]
2008	TX	Entergy TX	11,000	4,292	[13]
2008	TX	Oncor	77,905	9,160	[13]
2008	TX	Center Point	26,802	4,123	[13]
2008	TX	AEP Texas Central	24,868	5,095	[13]
2008	TX	AEP Texas North	12,950	3,128	[13]
2008	TX	SWEPCO	5,967	12,245	[13]

Table C. Average undergrounding costs (man-hours) per mile,[a] reported by 3 North Carolina utility companies.[7]

	AREA TYPE		
	URBAN	SUBURBAN	RURAL
Heavy commercial	$2,053,000	n/a	n/a
	(9,500)	n/a	n/a
3-phase bulk feeder	inc. above	$1,520,000	$590,000
	inc. above	(7,442)	(3,218)
3-phase primary tap	inc. above	$938,000	$456,000
	inc. above	(6,150)	(2,727)
1-phase primary tap	n/a	$350,000	$218,000
	n/a	(2,572)	(1,458)
Residential service drop per service	n/a	1,481	2,346
	n/a	(10)	(16)

[a]Data reported by Duke Power (36,000 miles of overhead distribution lines, 10,000 miles of underground distribution lines); Progress Energy Carolinas (28,000 overhead and 19,000 underground distribution lines); and Dominion North Carolina Power (4,131 miles overhead and 629 miles underground distribution lines).

Table D. Typical[a] underground cost drivers as a percentage of total overall cost.[11]

Cost item	%
Materials	34
Contractor Labor & Equipment	29
General & Administration overheads	22
Company Labor	8
Other	8

[a]Dominion Virginia Power, 2003.

Shaw® a world of Solutions™

02M062007D

Excerpted from a Briefing on the Study of the Feasibility and Reliability of Undergrounding Power Lines in the District of Columbia in Formal Case No. 1026

Shaw Consultants International, Inc.

Originally presented on September 30, 2010

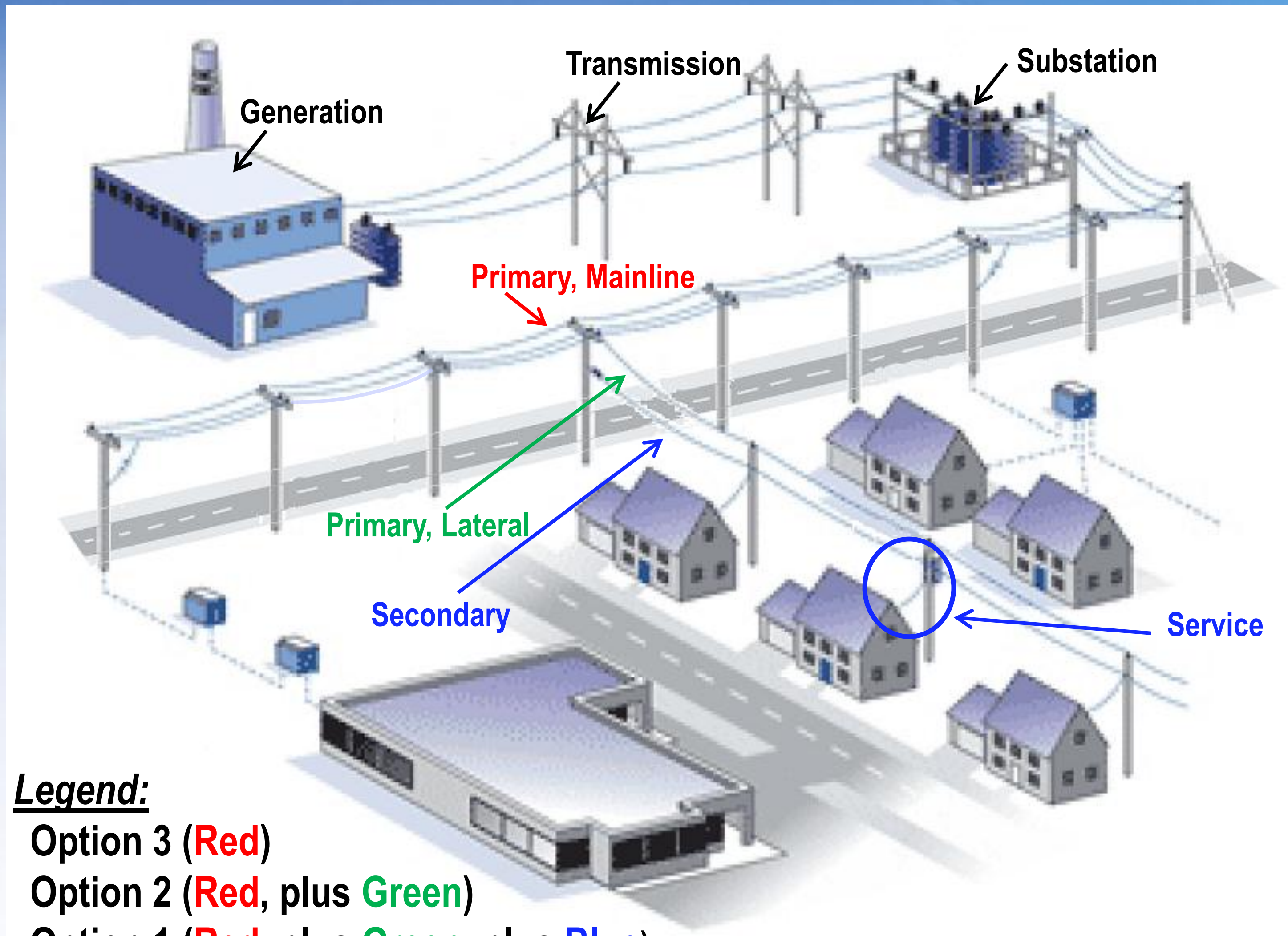
02M062007D

Shaw® a world of Solutions™

Project Purpose and Objectives

- Purpose
  - Study the economic and technical feasibility, and reliability implications of undergrounding power lines in the District of Columbia
- Objectives
  - Provide a comprehensive review and analysis of previous undergrounding studies and enhance Pepco efforts to date
  - Provide costs and reliability expectations for selected undergrounding alternatives to the existing overhead distribution system
  - Address barriers to undergrounding including costs, reliability, environmental concerns, economic disruption, etc., and how to overcome them
  - Develop and analyze the cost and reliability implications of undergrounding alternatives for the delivery of energy to customers in Washington, D.C.

District-wide Undergrounding Options Considered



Legend:

Option 3 (Red)

Option 2 (Red, plus Green)

Option 1 (Red, plus Green, plus Blue)

Note: Illustration is based on "Pepco, Summer Storms – July, August 2010" presentation, with modifications.

District-wide Undergrounding Option Implications

Option	Estimated Cost to UG ($2006)	Customers Affected (2008 data)	OH Customer Outages Avoided	Incremental Cost per Customer Affected	Relative Benefits
Undergrounding Mainline Primary (Option 3)	$ 1.1 Billion	73,384	65%	$14,990	Significant reliability improvement; least road-work needed to implement
Undergrounding Mainline Primary and Laterals (Option 2)	$ 2.3 Billion	97,650	87%	$49,452	Additional reliability benefits, almost equal to those of Option 1; addresses 87% of customer outages
Undergrounding All Existing Overhead Assets (Option 1)	$ 5.8 Billion	112,345	100%	$238,176	Slightly increased reliability over Option 2; maximum aesthetic benefits

02M062007D

Summary Recommendations/Observations

- Reliability improvement data is limited, typical conclusion reached is that the reduction in frequency of overhead outages is counter-balanced by increases in duration of underground outages
- TX and OK studies concluded that targeted UG can be cost-effective
  - A targeted approach would combine aggressive vegetation management, storm hardening of key outage-prone equipment and limited undergrounding of key circuits
- No study concluded that the <u>quantifiable</u> benefits provide justification for the increased costs of undergrounding <u>existing</u> overhead facilities on a <u>system-wide</u> basis
- Six states (including DC) require undergrounding of distribution lines for all <u>new</u> residential subdivisions
- In addition to these six states, municipal entities in six other states are requiring undergrounding in <u>new</u> residential subdivisions

02M062007D

Summary Recommendations/Observations (cont'd.)

- None of the 40 responding Commissions presently requires undergrounding of existing power lines
- Several Commission staff report that undergrounding becomes an issue after a major storm event, but is less of an issue once the high cost of undergrounding is evaluated
- Secondary assets have a relatively small effect on the total outage events and duration of the outages that the majority of customers experience
  - Any significant improvement in the performance of the District feeders will depend on making improvements in the overhead primary distribution system
- Shaw Consultants' UG cost estimate compares favorably with the original 2006 Pepco estimate of $3.5 million per mile
  - The difference in these estimates is not significant, given the scope of the project and the typical variations expected when comparing regional averages to specific local experience

Summary Recommendations/Observations (cont'd.)

- Undergrounding the Mainline Primary (Option 3) represents the most cost-effective solution if the number one concern is reliability – this option impacts the majority (65%) of customers affected by outages at the lowest cost of $1.1 billion
  - However, if aesthetics are a major driver, undergrounding all overhead electric distribution related assets (Option 1) is the only approach that has the potential to eliminate all overhead construction and its associated visual impacts, at an estimated cost of $5.8 billion – over five times the cost of Option 3 with an incremental reduction in customers affected of only 35%
- One way to mitigate the costs but retain a significant portion of the reliability and aesthetic benefits is a targeted approach where all overhead assets are replaced on a limited basis based on selection criteria related to frequency and duration of outage events, customers' willingness to pay, and other demographics
- Other benefits and costs associated with undergrounding remain difficult to quantify
  - Adding other environmental costs to the analysis would require significant additional research to put a value on the issues

02M062007D

Roundtable Recommendations for Improving System Reliability

Shaw Consultants International, Inc.

August 27, 2012

Recommendations

- ## Short Term

  1. In order to establish the appropriate priority for undergrounding, work to develop specific decision criteria for future undergrounding opportunities so that there is no uncertainty relative to cost recovery and support for a decision to invest.
  2. Targeted (smaller scale) UG opportunities should be explored in greater detail based on the decision criteria mentioned above.
  3. Site visits of currently ongoing major UG efforts would provide a very detailed first hand opportunity to see the effects of a major UG initiative first hand.

- ## Long Term

  1. Further investigate the potential added benefits and costs of undergrounding on a larger scale by building on the experience gained with smaller scale UG projects.
  2. Establish a cross agency team to investigate joint opportunities to underground electric facilities as part of major road construction or public works projects.
  3. Support R&D related activities focused on advancing underground related technologies.

DiDomencio Recommendations

Recommendations:

- Short Term
    1. In order to establish the appropriate priority for undergrounding, work to develop specific decision criteria for future undergrounding opportunities so that there is no uncertainty relative to cost recovery and support for a decision to invest.
    2. Targeted (smaller scale) UG opportunities should be explored in greater detail based on the decision criteria mentioned above.
    3. Site visits of currently ongoing major UG efforts would provide a very detailed first hand opportunity to see the effects of a major UG initiative first hand.
- Long Term
    1. Further investigate the potential added benefits and costs of undergrounding on a larger scale by building on the experience gained with smaller scale UG projects.
    2. Establish a cross agency team to investigate joint opportunities to underground electric facilities as part of major road construction or public works projects.
    3. Support R&D related activities focused on advancing underground related technologies.

Undergrounding for Improving the Resiliency of Maryland's Electric Distribution System

Bilal M. Ayyub, PhD, PE

Professor and Director

Center for Technology and Systems Management

University of Maryland, College Park

Telephone: 301-299-9375

ba@umd.edu

http://www.ctsm.umd.edu

Executive Order Roundtable Discussions

Miller Senate Office Building

August 27, 2012

CTSM

Technology for Intelligent Decisions

UNIVERSITY OF MARYLAND

Outline

- Governor's executive order
- Underground versus overhead lines
- Resiliency and lifecycle cost
- Worldwide perspectives
- System-level risk and predictive models
- Data needs
- Case studies
- Recommendations

Governor's Executive Order

- Improving resiliency by examining
  - **Effectiveness** and feasibility of undergrounding supply and distribution lines **in selected areas**
  - Options for other infrastructure investments in the electric distribution infrastructure with costs and benefits over various time periods
  - Options for financing and cost recovery for capital investments

Effectiveness → system model, risks, benefits, costs, and associated uncertainties

Underground versus Overhead lines

Hazards and failure causes

NEI Electric Power Engineering

Underground versus Overhead lines

- New York City – 100% underground since 1890’s
- Singapore – 100% underground
- Netherlands – 100% distribution underground
- Singapore – 100% underground
- Belgium – banned overhead in 1992
- Many questions, selected ones are:
  - What are the percentages for Maryland jurisdictions?
  - What are the corresponding failure rates?
  - What are the corresponding repair times?
  - How do they compare to other states?
  - What are the national and global trends?

Important Considerations

- Resiliency (reliability & recovery)
  - Reliability (time to failure or frequency)
    - Vulnerability to storms
    - Failure causes
    - Aging
  - Reparability (time to diagnose and repair)
  - Security
- Human health & safety (shocks, EMF, fire)
- Aesthetics
- Updatability
- Lifecycle cost effectiveness
- Regulatory and political considerations

Resiliency and Lifecycle Cost

- Resiliency
  - Failure rate (events per year): Underground 50% less than overhead
  - Life: Underground 30% to 50% less than overhead
  - Repairs: Underground more difficult than overhead, 58% longer to repair
- Lifecycle cost (transmission lines)
  - Initial cost for new lines: underground 4 to 6 times overhead
  - Initial cost for all existing lines: prohibitive? (125% rate increase?)

Worldwide Experience and Studies
(www.entergy.com)

- Edison Electric Institute & Energy Texas 2006/2007
  – Undergrounding costs 10 times more
- North Carolina (2002) and Florida (2003)
  – 80% to 125% rate increase for statewide conversion
- Other countries
  – 3% to 5% rate increase for 25% of Italy and UK
  – 16% rate increase for all of Italy
- Benefit/cost ratio
  – 0.38 (Virginia Corporation Commission 2004)
  – 0.11 (Australia 1998)

Systems Model: Risk Definition

ISO definition:

The effect[3] of uncertainty[2] upon objectives[1]

1. Objectives (resiliency, lifecycle cost, etc.)
2. Uncertainty (storms, performance, etc.)
3. Effect (affected customers)

Valuation of effects in monetary terms

Recommendation:

A system-wide risk model to identify overhead-line runs for undergrounding (among other options)

Risk Assessment and Management

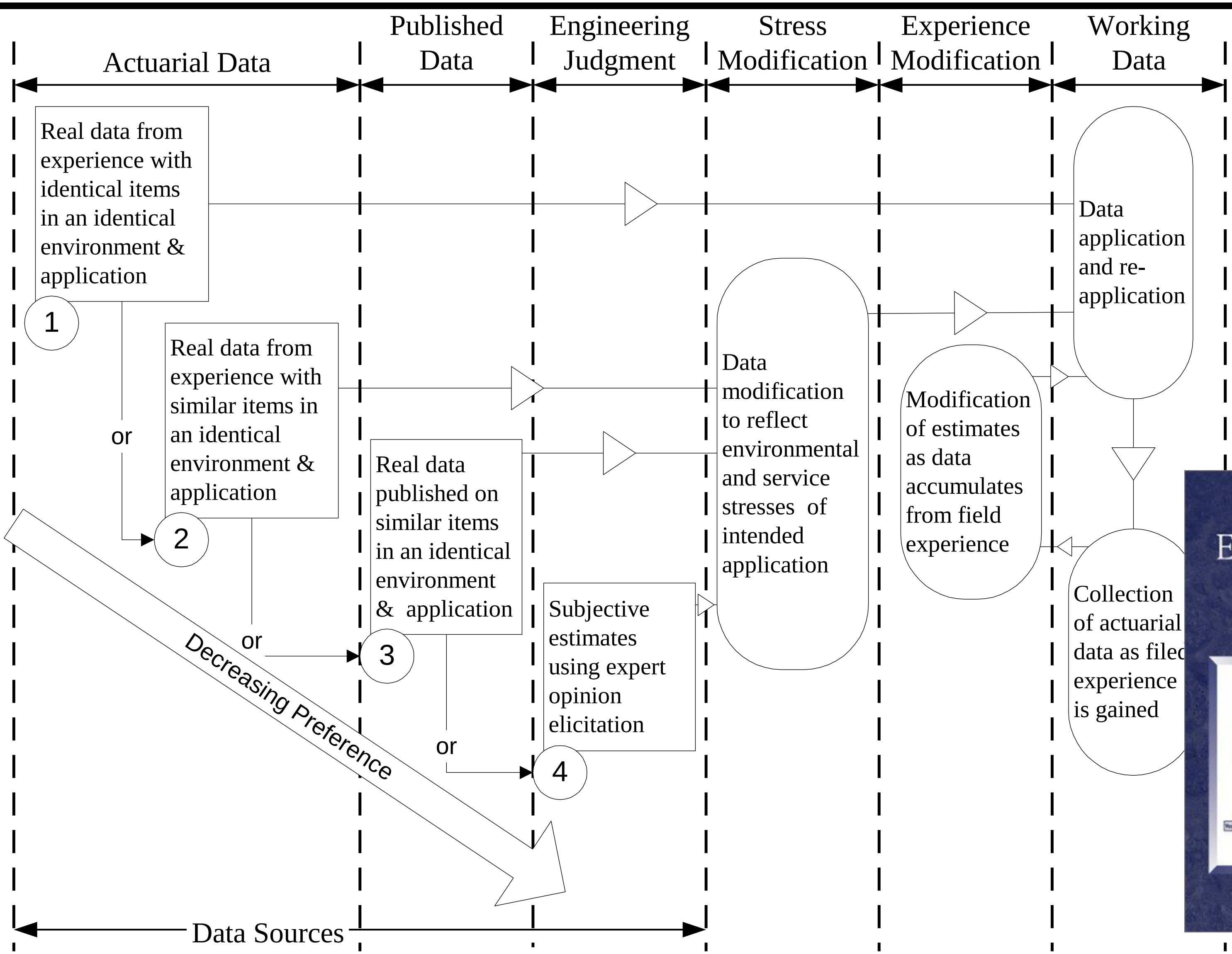
1. What could happen?
2. How likely is it to happen?
3. What are the consequences if it happens?

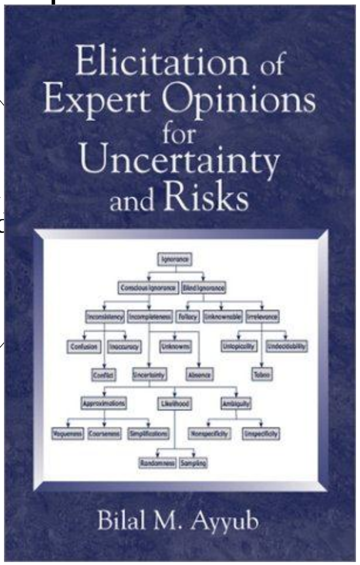
} **Risk Assessment**

4. What can be done?
5. What are the costs and benefits?
6. What effect will these actions have on future options?

} **Risk Management**

Data Sources for Quantitative Risk Analysis





Considerations in Decision Making

- What are the alternatives?
- Is an alternative cost effective?
- Does an alternative make it meet resiliency objectives?
- Is it affordable?
- Does it limit future options?
- Are there other considerations, political, legal, etc.?

Risk Management

- Identify alternatives
- Assess benefits and costs of each
- Assess impact of strategy on future options

$$\text{Benefit} = (\text{Risk Before}) - (\text{Risk After})$$

$$\text{B/C Ratio} = \frac{\text{Benefit}}{\text{Cost}}$$

$$P\left(\frac{\text{Benefit}}{\text{Cost}} \geq 1\right) = 1 - P(\text{Benefit} - \text{Cost} \leq 0)$$

Hurricane Katrina: Risk Methodology

Case study

From IPET Documents

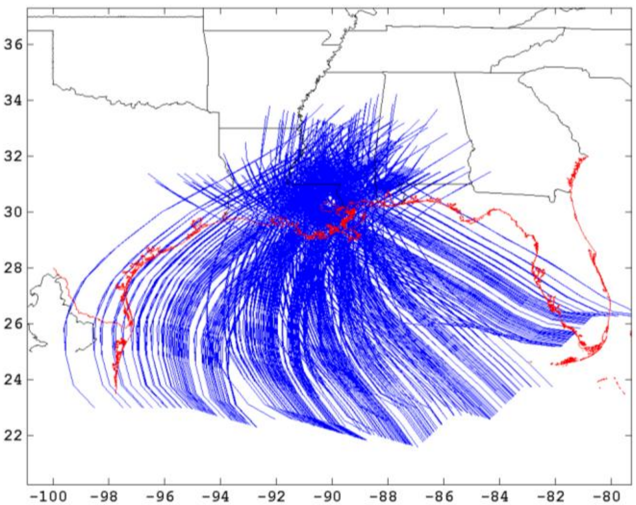
Hurricanes

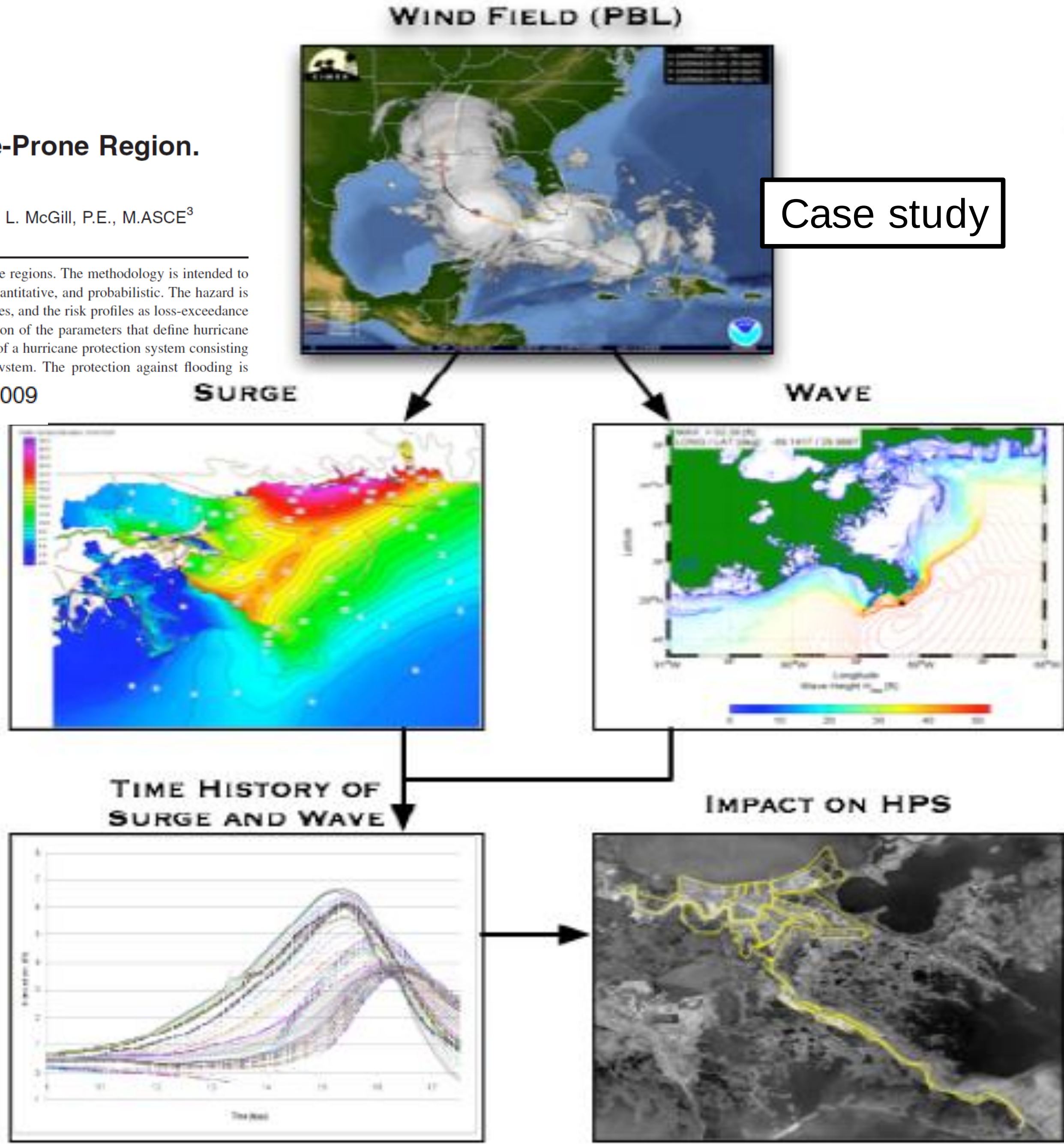
Risk Analysis of a Protected Hurricane-Prone Region. I: Model Development

Bilal M. Ayyub, P.E., F.ASCE[1]; Jerry Foster, M.ASCE[2]; and William L. McGill, P.E., M.ASCE[3]

Abstract: A risk analysis methodology is presented in this paper for protected hurricane-prone regions. The methodology is intended to assist decision and policy makers, and has the characteristics of being analytic, transparent, quantitative, and probabilistic. The hazard is quantified using a probabilistic framework to obtain hazard profiles as elevation-exceedance rates, and the risk profiles as loss-exceedance rates that are based on a spectrum of hurricanes determined using a joint probability distribution of the parameters that define hurricane intensity. The resulting surges, waves, and precipitations are used to evaluate the performance of a hurricane protection system consisting of a series of basins and subbasins that define the interior drainage characteristics of the system. The protection against flooding is

38 / NATURAL HAZARDS REVIEW © ASCE / MAY 2009



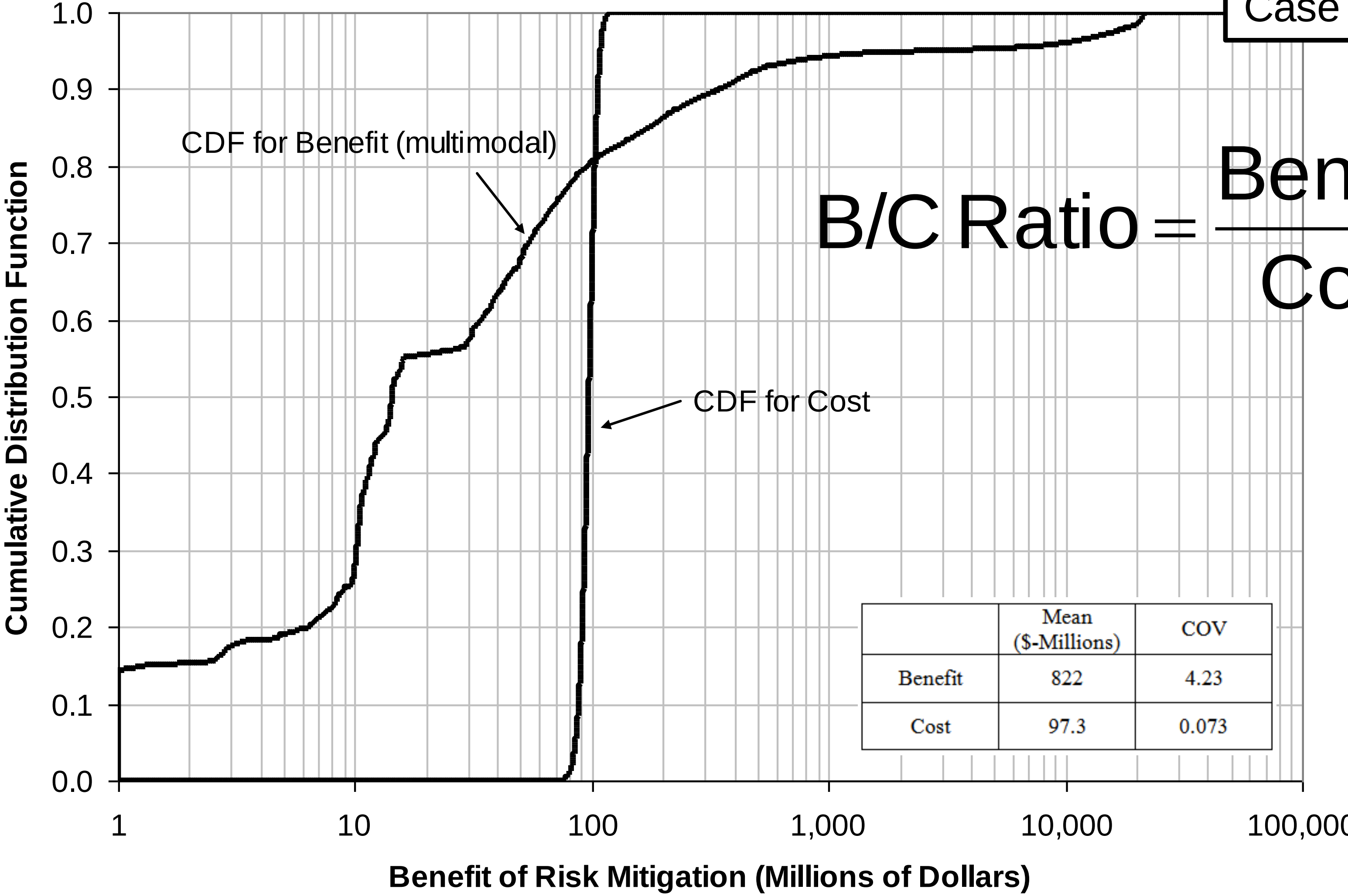


Case study

From IPET Documents

Hurricane protection system

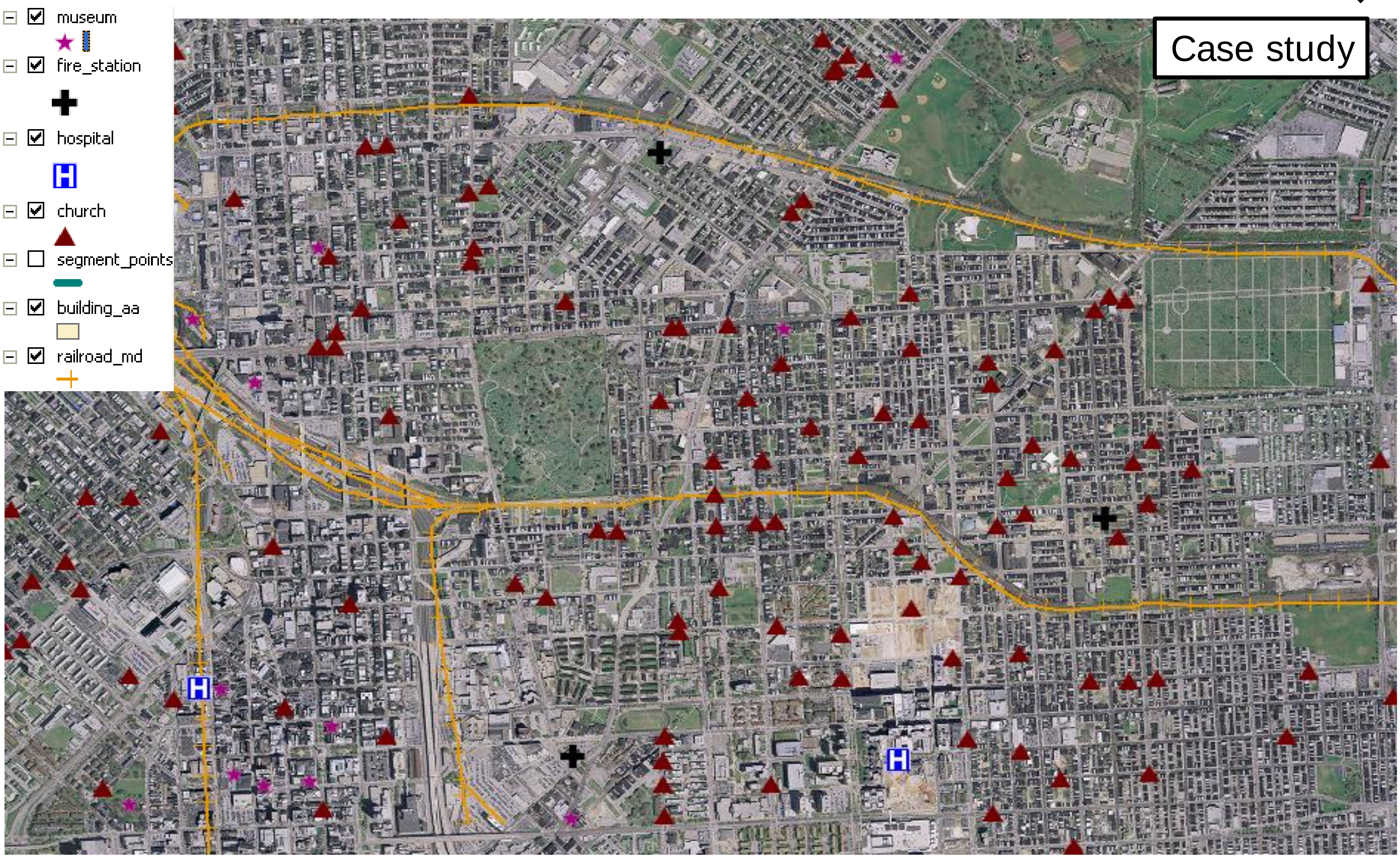
Case study



$$\text{B/C Ratio} = \frac{\text{Benefit}}{\text{Cost}}$$

	Mean ($-Millions)	COV
Benefit	822	4.23
Cost	97.3	0.073

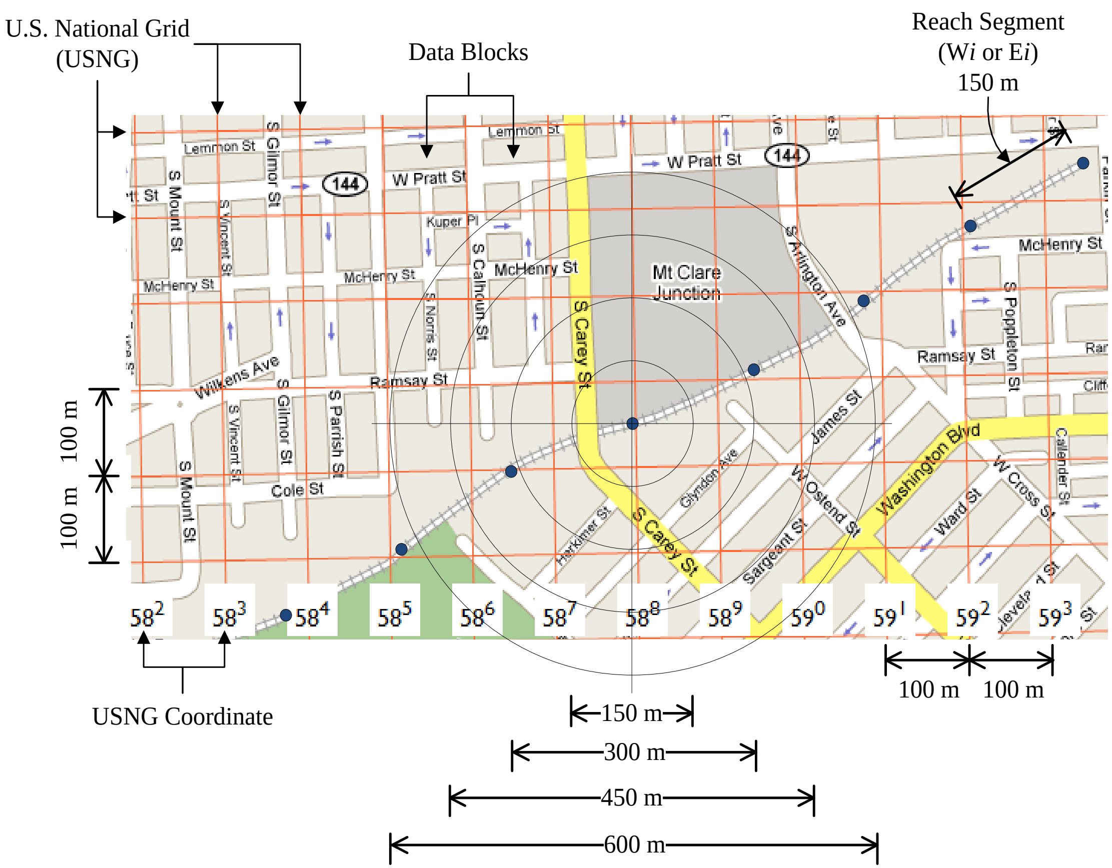
Rail Safety and Security

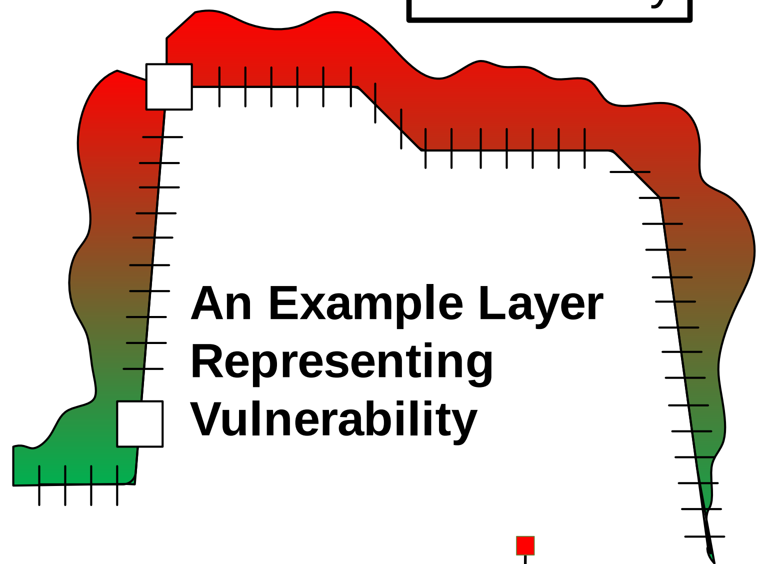


Rail Safety and Security

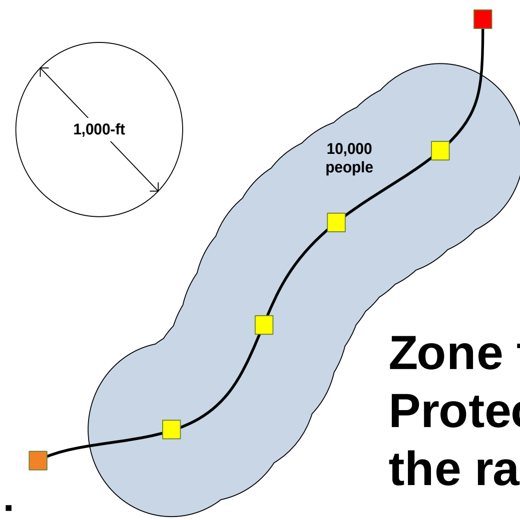
A *rolling* incident with four influence circles

Case study





An Example Layer Representing Vulnerability



Zone to Protect along the railroad

Inventory: people, structures, schools, utilities, police resources, fire stations, hospitals, …

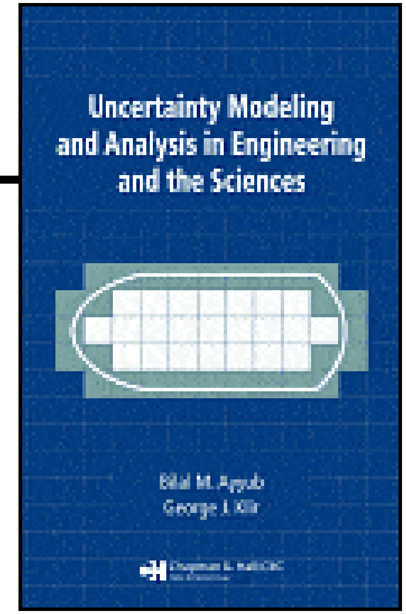
Recommendations

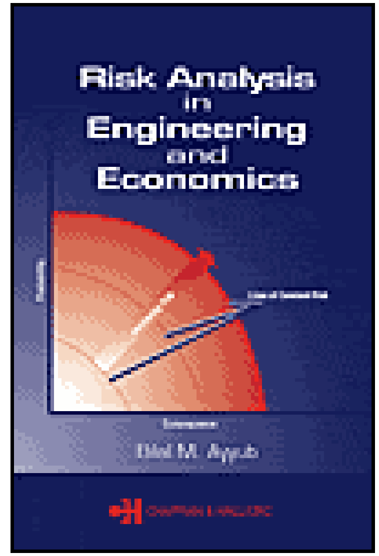
- Develop a system-wide quantitative risk model for informing decision and policy making
- Use the “20/80 rule” to identify 20% of line segments that account for 80% of the affected population
- Develop a strategy table of alternatives, e.g.,
  - Undergrounding
  - Looped distribution system
  - Centralized LNG generators

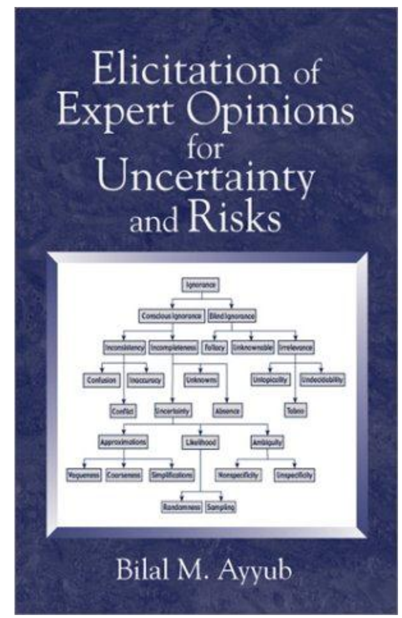
  Benefit-cost analysis of alternatives

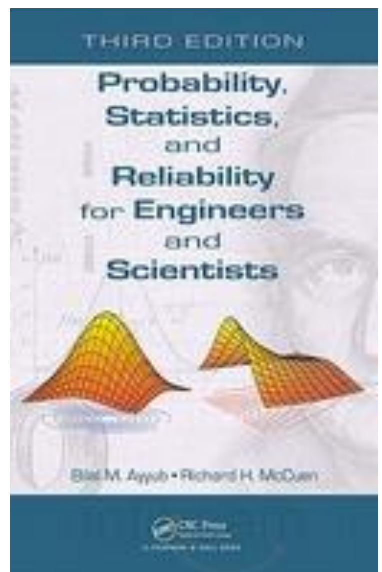
Selected Publications

- Uncertainty Analysis in Engineering and the Sciences, Chapman & Hall/CRC Press, 2006
- Risk Analysis in Engineering and Economics, Chapman & Hall/CRC Press, 2003
- Elicitation of Expert Opinions for Uncertainty and Risks, CRC Press, FL, 2001
- Probability, Statistics and Reliability for Engineers and Scientists, Chapman & Hall/CRC Press, 2011









Undergrounding for Improving the Resiliency of the Maryland's Electric Distribution System: a Systems Model for Decision Making

Bilal M. Ayyub, PhD, PE, Professor and Director
Center for Technology and Systems Management, Department of Civil & Environmental Engineering, University of Maryland, College Park, MD 20742
Telephone: 301-299-9375, ba@umd.edu, http://www.ctsm.umd.edu

Executive Order Roundtable Discussions
Miller Senate Office Building
August 27, 2012

I greatly appreciate the opportunity to join you at this roundtable discussion. I am Bilal Ayyub, a Professor of Civil & Environmental Engineering and the Director of the Center for Technology and Systems Management at the University of Maryland, College Park. I have served on the State of Maryland Governor's Emergency Management Advisory Council since 2011, and specialize in risk analysis, uncertainty modeling, decision analysis, and systems engineering.

The Governor's Executive Order calls for improving resiliency of Maryland's electric distribution system by examining:

- The effectiveness and feasibility of undergrounding supply and distribution lines in selected areas;
- Options for other infrastructure investments in the electric distribution infrastructure with costs and benefits over various time periods; and
- Options for financing and cost recovery for capital investments.

The focus of my testimony is on the first item.

Many cities and countries have moved lines from overhead to underground, for example, New York City with 100% underground since 1890's, Singapore with 100% underground, the Netherlands with 100% distribution underground, Belgium banning overhead in 1992. I suggest the following questions to inform decision makers:

- What are the percentages for Maryland jurisdictions?
- What are the corresponding failure rates?
- What are the corresponding repair times?
- How do they compare to other states?
- What are the national and global trends?

These questions require additional research.

Underground and overhead lines have different failure causes and modes that should be carefully characterized. Examples are provided in my PowerPoint slides.

Decision making requires the definition of criteria based on meeting societal needs. The criteria should include:

- Resiliency (recovery)
    - Reliability (time to failure or frequency)
        - Vulnerability to storms

        - Failure causes
        - Aging
    - Reparability (time to diagnose and repair)
- Security
- Human health & safety (shocks, EMF, fire)
- Aesthetics
- Updatability
- Lifecycle cost effectiveness
- Regulatory and political considerations

My brief literature review revealed several observations that are noteworthy. For example, failure rate (events per year) for underground lines is 50% less than overhead lines, the life of underground lines is 30% to 50% less than the life overhead lines, and repairing underground lines is more difficult than overhead lines requiring 58% longer times to repair. The lifecycle cost for transmission lines includes initial cost that is, in the case of new underground lines, 4 to 6 times the overhead lines, and, in the case of existing overhead lines, can be prohibitive and can result in as much as an 125% rate increase. These estimates were provided by utilities.

The national and worldwide perspectives (www.entergy.com) on this subject vary as follows:

- Edison Electric Institute & Energy Texas 2006/2007 reported that undergrounding transmission costs 10 times more than overhead lines
- The State of North Carolina (2002) and the State of Florida (2003) reported 80% to 125% rate increase for statewide conversion
- Other studies reported 3 to 5% rate increase for 25% undergrounding of lines in Italy and the United Kingdom, and 16% rate increase for undergrounding lines in all of Italy.
- Benefit/cost ratio reported are 0.38 (Virginia Corporation Commission 2004) and 0.11 (Australia 1998)

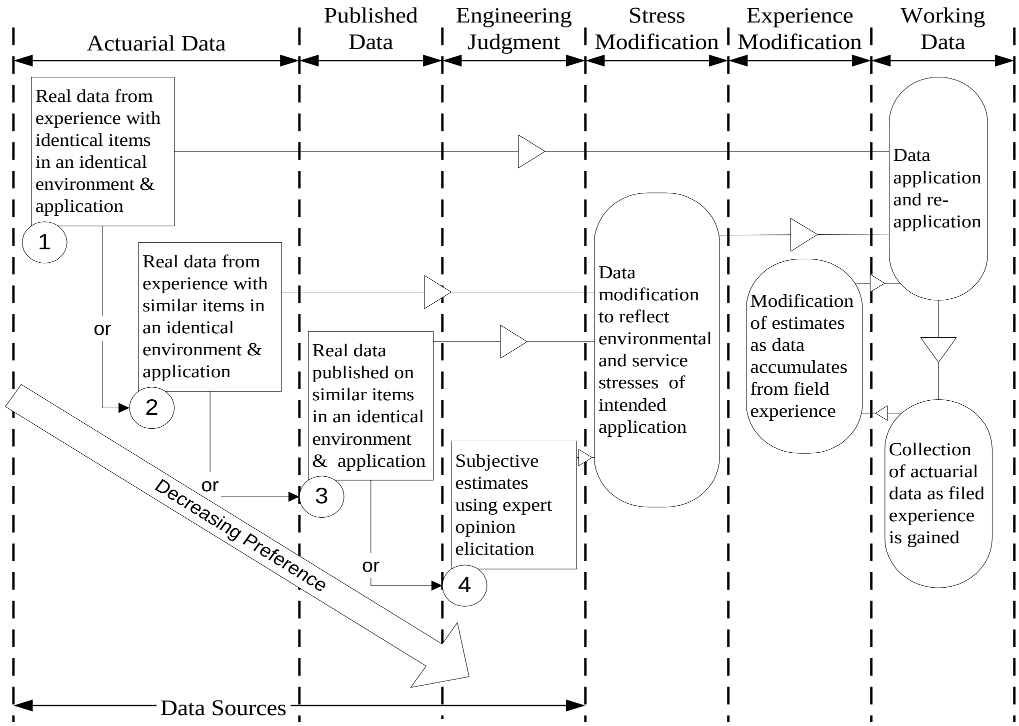
Deciding on undergrounding supply and distribution lines based on the effectiveness and feasibility in selected areas requires the use of a system-wide decision making framework based on risk concepts. For this purpose, risk can be defined (according to the ISO, see also Ayyub 2003) as the effect of uncertainty upon objectives. Let's consider the three keywords in the definition. The objectives or criteria were discussed previously to include resiliency and lifecycle cost, etc. The uncertainties results from storms, performance, etc. The effects include affected customers. The valuation of effects in monetary terms requires the use of concepts as covered in risk analysis sources (such as Ayyub 2003). I recommend the development of a system-wide risk model to identify overhead-line runs for undergrounding or other treatments based on the criteria previously discussed.

Assessing and managing risk requires addressing the following questions:

- What could happen?
- How likely is it to happen?
- What are the consequences if it happens?
- What can be done?
- What are the costs and benefits?

- What effect will these actions have on future options?

Data sources for risk studies are schematically represented in the following figure (Ayyub 2001 and Ayyub 2003):



Most studies require the use of mixed data.

Appropriate decision making requires addressing the following questions:

- What are the alternatives?
- Is an alternative cost effective?
- Does the implementation of an alternative make the system meet resiliency objectives?
- Is it affordable?
- Does it limit future options?
- Are there other considerations, political, legal, etc.?

Risks can be rationally managed by resource allocation to risk treatments. Defining this allocation requires identifying alternatives, assessing benefits and costs of each, and assessing the impact of strategy on future options (Ayyub 2003). The benefit associated with an alternative can be computed as follows:

Benefit = (Risk Before) – (Risk After)

The benefit-to-cost ratio is

$$\text{B/C Ratio} = \frac{\text{Benefit}}{\text{Cost}}$$

Recognizing the uncertainties in the benefit and cost, the probability of not realizing the net benefits is:

$$P\left(\frac{\text{Benefit}}{\text{Cost}} \geq 1\right) = 1 - P(\text{Benefit} - \text{Cost} \leq 0)$$

Two case studies were presented and the relevant papers are appended to this report. These two national efforts are:

- The risk model development effort for the Army Corps after Hurricane Katrina. I would like to share with you a technical paper as a result of this effort. This model has been used by the Army Crops to enhance the protection system.
- The risk model for resource allocation to protect critical infrastructure that was developed for DHS and used for several years by several sectors. I am attaching a paper that describes this model.

Short-term Recommendations

My recommendations on the subject of undergrounding for improving the resiliency of the Maryland's electric distribution system are

- Development of a system-wide quantitative risk model for informing decision and policy making processes
- Encouraging the undergrounding of an additional 20 to 30% of the supply and distribution lines using perhaps the 20/80 rule to identify 20% of lines that account for 80% of affected population
- Developing a strategy table of alternatives with benefit-cost analysis of alternatives, e.g., undergrounding, looped distribution systems, centralized LNG generators, etc.

Long-term Recommendations

I would like you to consider power, and broadly energy, related issues using systems thinking in order to develop strategies that can address potential impacts due to climate change and emissions, population increases, consumption behavior and affordability, aging of infrastructure, alternate energy sources, smart grids, distributive generation, and security and emergency needs. System-wide models with appropriate treatments of uncertainty and interactions are essential for success. Developing a total value structure and functional hierarchy on the basis of electric power sufficiency, availability and resiliency, and physical and cost efficiency would offer a strong basis to identify cost-effective strategies. These strategies should be evaluated using risk analysis methods as described by Ayyub (2003).

Thank you for the opportunity to join you at this roundtable discussion.

References

Ayyub and Klir, Uncertainty Analysis in Engineering and the Sciences, Chapman & Hall/CRC Press, 2006.

Ayyub, Risk Analysis in Engineering and Economics, Chapman & Hall/CRC Press, 2003

Ayyub, Elicitation of Expert Opinions for Uncertainty and Risks, CRC Press, FL, 2001

Ayyub and McCuen, Probability, Statistics and Reliability for Engineers and Scientists, Chapman & Hall/CRC Press, 2011

Undergrounding for Improving the Resiliency of the Maryland's Electric Distribution System: a Systems Model for Decision Making

Bilal M. Ayyub, PhD, PE, Professor and Director
Center for Technology and Systems Management, Department of Civil & Environmental Engineering, University of Maryland, College Park, MD 20742
Telephone: 301-299-9375, ba@umd.edu, http://www.ctsm.umd.edu

Executive Order Roundtable Discussions
Miller Senate Office Building
August 27, 2012

Short-term Recommendations

My recommendations on the subject of undergrounding for improving the resiliency of the Maryland's electric distribution system are

- Development of a system-wide quantitative risk model for informing decision and policy making processes
- Encouraging the undergrounding of an additional 20 to 30% of the supply and distribution lines using perhaps the 20/80 rule to identify 20% of lines that account for 80% of affected population
- Developing a strategy table of alternatives with benefit-cost analysis of alternatives, e.g., undergrounding, looped distribution systems, centralized LNG generators, etc.

Long-term Recommendations

I would like you to consider power, and broadly energy, related issues using systems thinking in order to develop strategies that can address potential impacts due to climate change and emissions, population increases, consumption behavior and affordability, aging of infrastructure, alternate energy sources, smart grids, distributive generation, and security and emergency needs. System-wide models with appropriate treatments of uncertainty and interactions are essential for success. Developing a total value structure and functional hierarchy on the basis of electric power sufficiency, availability and resiliency, and physical and cost efficiency would offer a strong basis to identify cost-effective strategies. These strategies should be evaluated using risk analysis methods as described by Ayyub (2003).

References

Ayyub and Klir, Uncertainty Analysis in Engineering and the Sciences, Chapman & Hall/CRC Press, 2006.

Ayyub, Risk Analysis in Engineering and Economics, Chapman & Hall/CRC Press, 2003

Ayyub, Elicitation of Expert Opinions for Uncertainty and Risks, CRC Press, FL, 2001

Ayyub and McCuen, Probability, Statistics and Reliability for Engineers and Scientists, Chapman & Hall/CRC Press, 2011

State of Maryland

Improving the Reliability and Resiliency of Maryland's Electrical Distribution Systems

Roundtable Meeting of August 27, 2012
Annapolis, Maryland

George E. Owens Testimony Summary

The devastating effects of storm damage to Maryland's electrical distribution systems during recent years have heightened the awareness of citizens and governmental officials alike to the sizeable and growing cost from the loss of vital electrical service. The toll of human suffering as well as the cost to the economy of the State of Maryland have added enormous weight to the importance of these issues.

Bringing long-term robust solutions to these increasing problems will require thorough engineering review, extensive application of available technologies and above all, close coordination and cooperation between electric utilities, governmental agencies, and ultimately the customers served by the distribution systems. To achieve lasting success, utilities must be willing to devote engineering time and invest in substantial capital improvements. Governmental agencies and the customers themselves must be willing to work with the utilities to facilitate the necessary system improvements. Reliable and resilient electrical distribution systems do not happen by accident. They are the result of a coordinated effort between utilities, governmental agencies, and customers.

This process must begin with an understanding of the functional components of all distribution systems. These are the local substations, the main trunk distribution circuits, and the lateral tap lines which ultimately deliver electrical power to most customers. Reliability and resiliency must be achieved within each of these sectors. Some of the most important technological advances over the last decade have been in distribution circuit design. Advances in wireless communication technologies coupled with the deployment of SCADA operable mid-circuit reclosers and load-break disconnect switches and their integration with computerized distribution automation and restoration systems have brought invaluable tools into the hands of utility system operators. In addition, the advancements in directional boring and flexible conduit techniques coupled with the newest jacketed cross-linked polyethylene and EPR rubberized primary cable systems have simplified the installation of underground utilities in populated areas while substantially lengthening the life expectancy of the resultant systems.

Maryland can significantly improve the reliability and resiliency of its electrical distribution systems and thus achieve vast improvements in the storm readiness of these critically important assets. Investment in circuit sectionalizing equipment and computerized distribution automation and restoration systems will be crucial. Likewise, the selective undergrounding of lateral distribution lines within the worst performing subdivisions throughout the state will be especially important. The following are the recommended steps to achieving these objectives.

State of Maryland

Improving the Reliability and Resiliency of Maryland's Electrical Distribution Systems

Roundtable Meeting of August 27, 2012
Annapolis, Maryland

Short-Term Recommendations

1. Each Maryland electrical utility should compute CAIFI (Customer Average Interruption Frequency Index) and CAIDI (Customer Average Interruption Duration Index) outage indices, with the inclusion of all storm related outages for each of its distribution circuits. From the referenced CAIFI and CAIDI studies, each utility should select for immediate system upgrades the 10% worst performing circuits with the highest CAIFI and CAIDI indices.

2. Each utility should install SCADA operable mid-circuit reclosers on each of the 10% worst performing circuits identified previously that are greater than two miles in length and integrate these with the utility's computerized automated restoration system.

3. Each utility should install SCADA operable load-break disconnect switches at circuit tie and sectionalizing locations on each of the 10% worst performing circuits identified previously that are greater than two miles in length and integrate these with the utility's computerized automated restoration system.

Long-Term Recommendations

1. Each utility should install SCADA operable mid-circuit relcosers and SCADA operable load-break disconnect switches for improved circuit sectionalizing on all remaining overhead distribution circuits that are greater than two miles in length and integrate these devices with the utility's automated restoration system.

2. Each utility should compute CAIFI and CAIDI outage indices with the inclusion of all storm related outages for each residential subdivision served by the utility. From the referenced CAIFI and CAIDI studies, each utility should select the 10% worst performing residential subdivisions with the highest CAIFI and CAIDI indices.

3. Based upon review and approval by appropriate governmental agencies, each utility should selectively underground the lateral tap circuits which supply electrical power to the previously identified worst performing subdivisions in its territory utilizing fully jacketed cross-linked polyethylene or EPR primary cables utilizing directional bore and flexible conduit installations.

4. Each utility should develop a twenty-year plan for the eventual undergrounding of all remaining lateral tap circuits supplying electrical power to residential subdivisions.

Overview of Pepco's Undergrounding Initiatives

Maryland
August 27, 2012

Discussion Topics

- Introduction
- Overview of Pepco's Electric System
- Pepco's Undergrounding Study: Purpose, Objectives and Scope
- Issues to be addressed
- Undergrounding – Pros and Cons
- Comparison of Undergrounding to Overhead System Performance
- Possible Undergrounding Scenarios
- Appendix
  - Analysis Structure
  - Typical Design Considerations

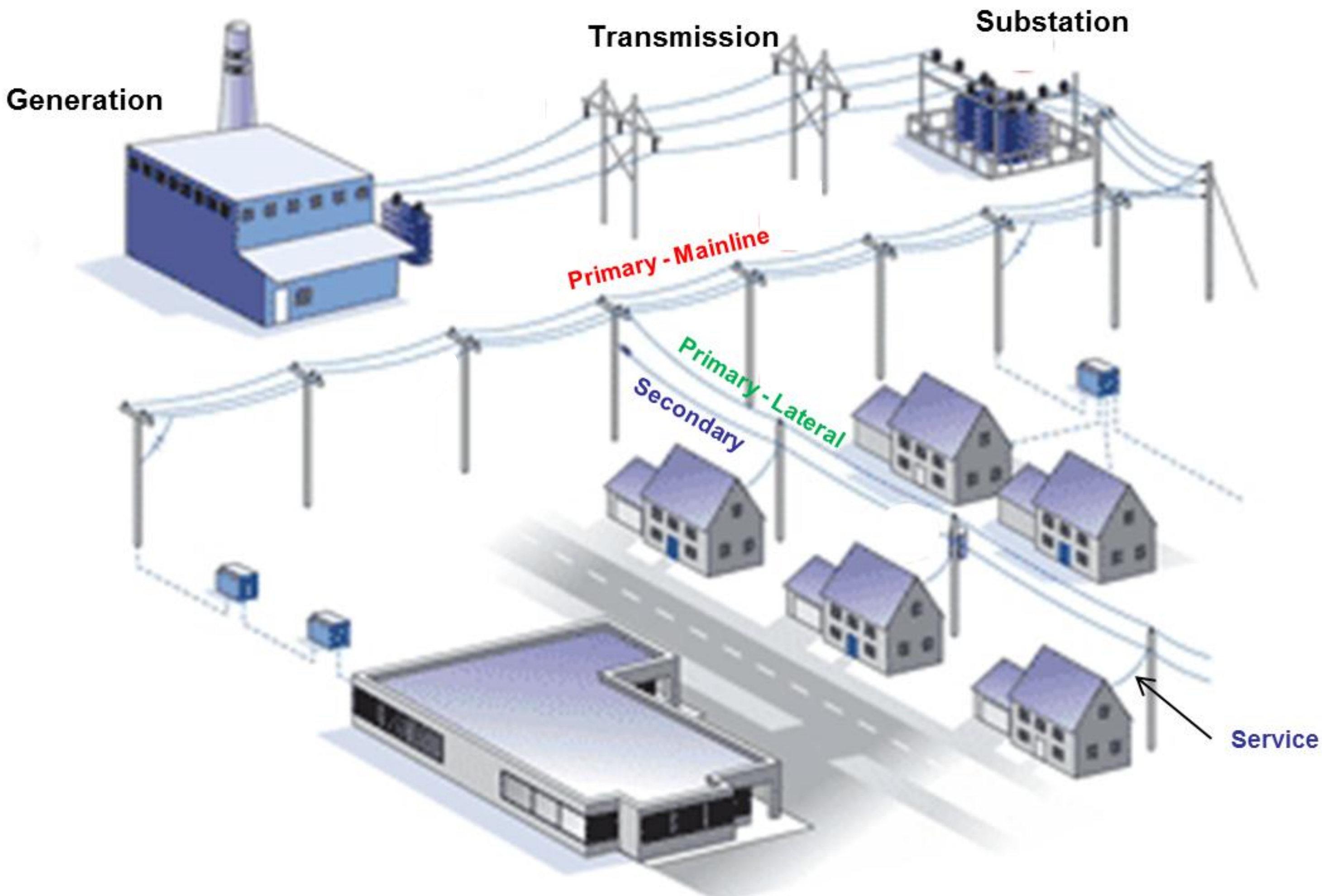
Introduction

- Pepco's distribution system is a mixture of both OH and UG configuration
- Pepco plans to file with the Commission no later than the end of this year a study to evaluate the undergrounding of existing overhead infrastructure
- Topics to be covered in the study will include:
  1. UG Project Selection Criteria
  2. Cost Components
  3. Design and Construction Criteria
  4. Undergrounding Options
  5. Expected Reliability Benefits, and
  6. Recommendations for Pilot Projects

- The results of this study will be presented to the Commission to provide insight and data to inform and support decisions on how to move forward with undergrounding initiatives in Maryland

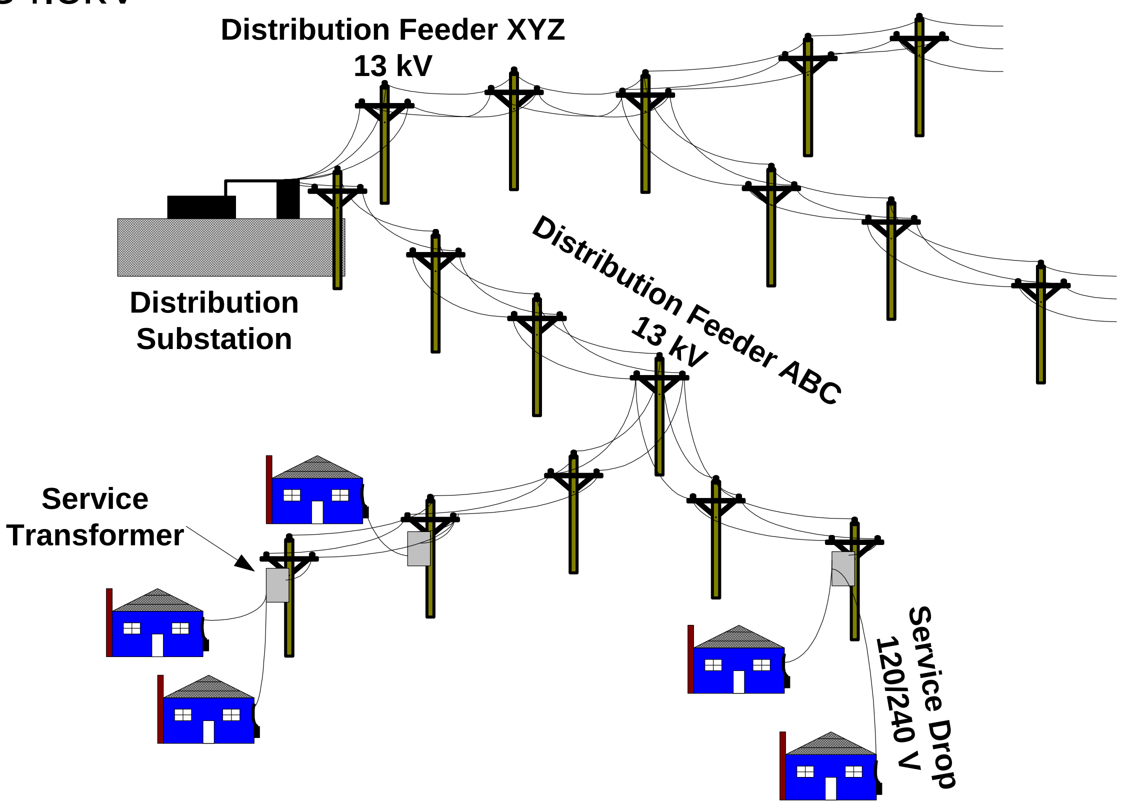
Distribution Operations Overview

pepco
A PHI Company



Distribution Subsystem

- Distribution is the process of delivering electric power from the transmission system to end-use customers
- Most typically accomplished via radial medium voltage feeders and low voltage service connections
- Typical voltages – 12kV to 34.5kV
- Home delivery voltages are usually 120/240 volts



Pepco's Maryland Electric System

pepco
A PHI Company

Number of Substations	UG feed	OH feed	Total
Distribution	12	52	64
Transmission	8	5	13
Total	20	57	77
Circuit Miles	**UG**	**OH**	**Total**
Primary	4,994 miles (59%)	3,487 miles (41%)	8,481 miles
Secondary	1,564 miles (36%)	2,723 miles (64%)	4,287 miles
Totals	6,558 miles (51%)	6,210 miles (49%)	12,769 miles

Customers by feeder	4kV	13kV	Total	% of Total
>=85% Overhead	49	104,237	104,286	19.6%
100% Underground	-	9,204	9,204	1.7%
Mixed	-	419,265	419,265	78.7%
Total	49	532,706	532,755	

Customers by Service	Total	% of Total
Overhead	237,746	44%
Underground	296,840	56%
Total	534,586	100%

Pepco's UG Study: Purpose, Objectives and Scope

pepco
A PHI Company

Purpose	1) Produce an analysis and thorough study of the technical feasibility, infrastructure options and reliability implications of undergrounding new or existing overhead electric distribution in Maryland to assist stakeholders in defining a way forward for these types of infrastructure improvements and additions.
Objective	2) Identify high level probable reliability outcomes during major storms from four illustrative types of distribution feeders i.e. majority underground, majority overhead, mixed overhead & underground and feeders serving public welfare and safety agencies and infrastructure (such as hospitals, water and sewage treatment facilities, etc.).

Scope

Background		Examination		Conclusion	
Identify design principles and design implications of Pepco's System Today (History)		Analyze appropriate Undergrounding Options, Costs and Reliability Benefits Estimates		Findings	Summary
Research Comparable Efforts to Pepco System	Include appropriate innovations for Pepco's System of Tomorrow	Investigate Pepco's System Performance In light of major storms	Consider Construction Process	Recommendations	
Discuss the pros and cons	Identify Options for Undergrounding	Discuss Associated Work – Coordination with other Utilities	Challenges, Benefits, Selection Process		

Undergrounding Scenarios Being Considered and Potential Impact on Outages

pepco
A PHI Company

	Scenario Description	Reduces outages during*		
		Blue Sky	Small Storms	Major Storms
1	Underground mainline primary; retain the current poles, transformers and feed up the poles; retain all lateral overhead primary.	LOW	MEDIUM	LOW
2	Underground all primary; retain the current poles, secondary cables, services and secondary up the poles; remove all the primary from the poles.	HIGH	HIGH	MEDIUM
3	Underground all primary, secondary and services up to the residence; option of installing new customer meter box.	HIGH	HIGH	HIGH
4	Underground sections of the high voltage substation supply lines in accordance with desired future configuration.	LOW	LOW	HIGH

*Based on preliminary assumptions.

Development of Potential Pros and Cons for Undergrounding

pepco
A PHI Company

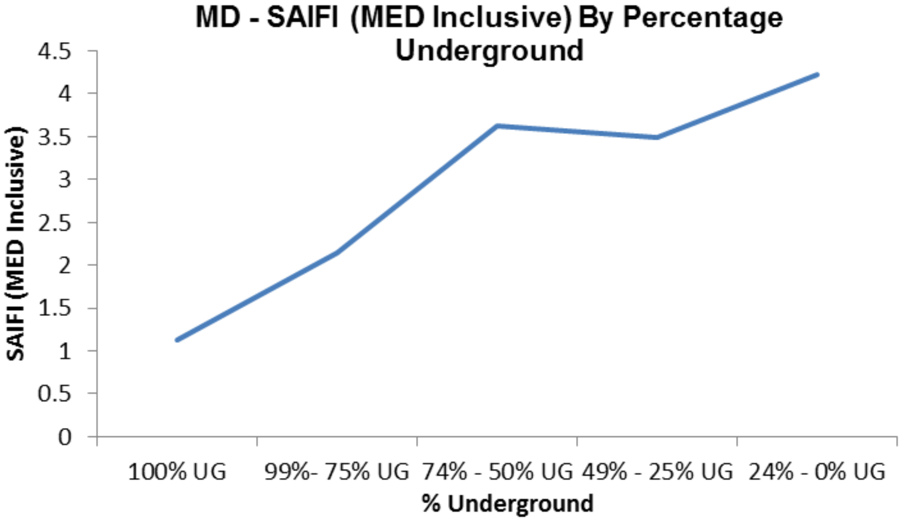
Pros:

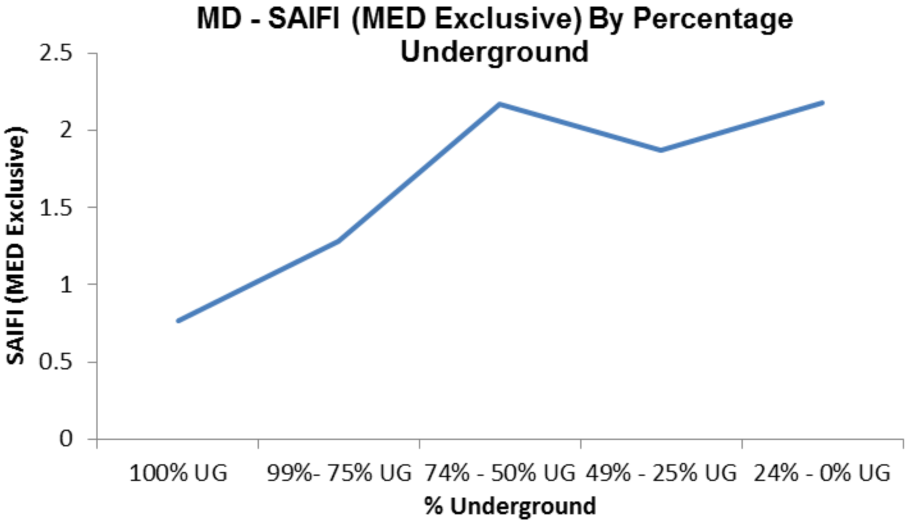
- Protection from outages caused by trees, wind, ice, snow, rain, lightning, animals, and vehicles;
- Ability to optimize capital spending previously dedicated to reliability improvement efforts to offset the cost of undergrounding;
- Improved aesthetics (if cable and phone lines are also placed underground);
- Lower tree trimming cost;
- Lower storm damage and associated restoration cost;
- Fewer long major storm outages and associated lifestyle disruptions and economic impact to customers;
- Fewer momentary interruptions;
- Improved customer relations regarding tree trimming & fewer outages;
- Future construction methods and technology will allow for faster restoration time compared to past design due to greater system interconnection flexibility.

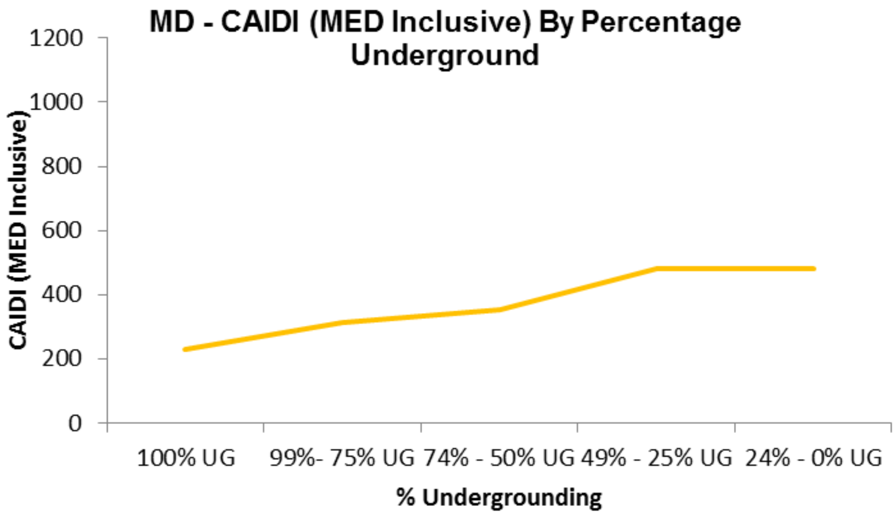
Cons:

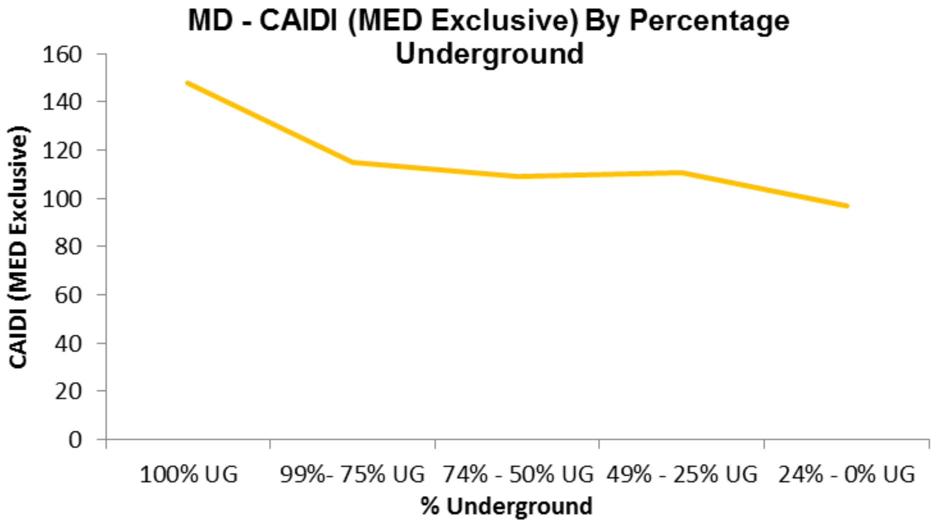
- Higher costs than overhead for initial construction;
- UG equipment may not last as long as OH facilities due to environmental conditions;
- Failed cable and equipment take longer to locate and repair;
- Possible tree damage in conversion areas;
- Susceptibility to flooding that could result in outages;
- Generally higher replacement costs than overhead lines;
- Potential longer duration to find and fix outage

Reliability Comparison of Overhead and Underground Systems







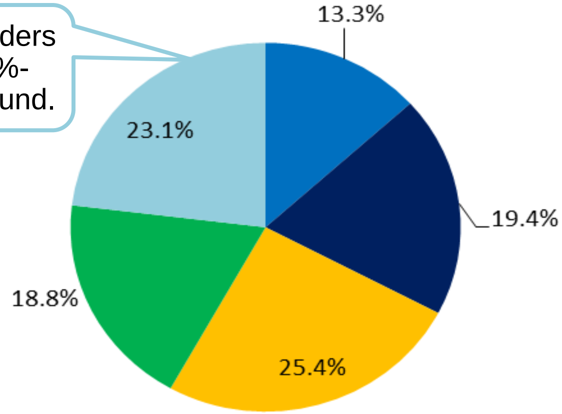


SAIFI – System Average Interruption Frequency Index; CAIDI – Customer Average Interruption Duration Index;
Major Event Days (MED) Exclusive - Excludes MEDs; Major Event Days (MED) Inclusive – Includes MEDs

Example of a Reliability Comparison in Maryland

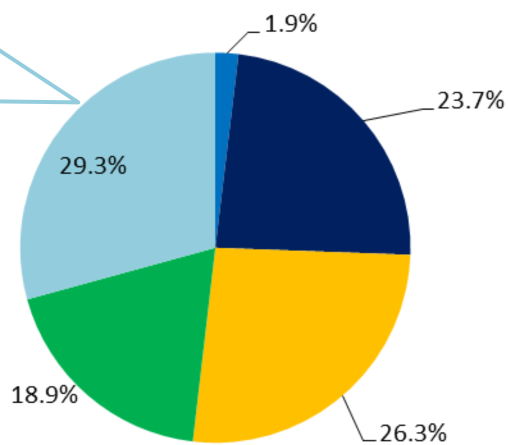
MD - % Feeders by Underground Category

23.1% of Feeders in MD are 24%-0% Underground.



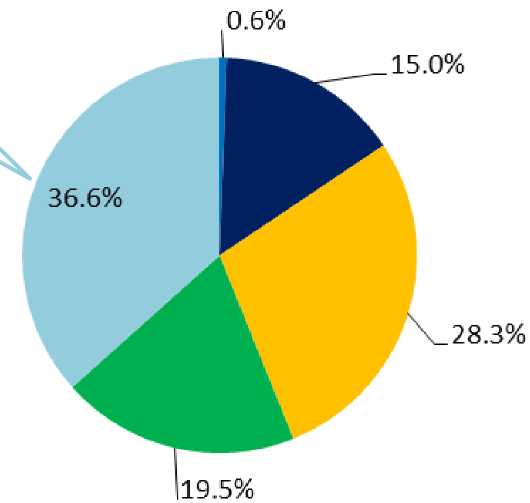
MD - % Customers Served by Underground Category

29.3% of Customers in MD are on 24%-0% Underground feeders.



MD - % Customers Affected (Storm Inclusive) by Underground Category

36.6% of outages during storm days.

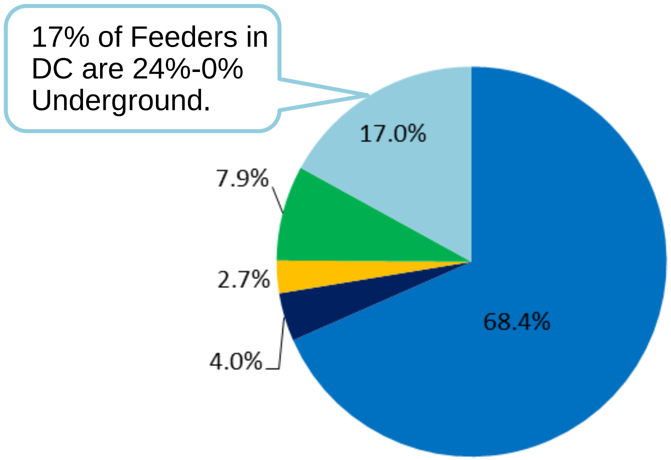


23.1% of feeders in Maryland are more then 75% overhead construction and account for 36.6% of the customer outages.

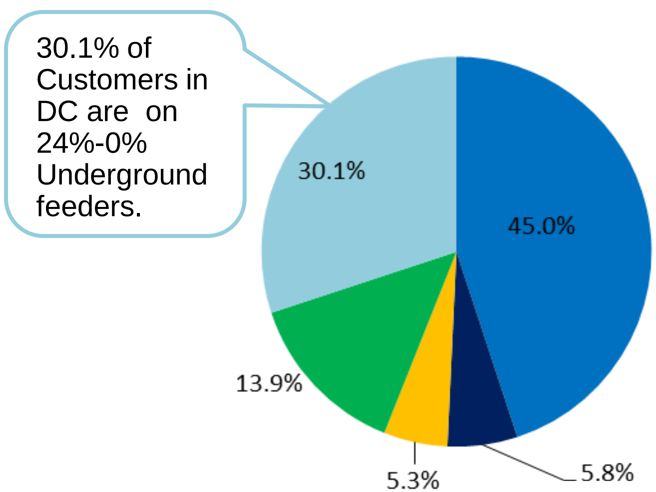
Legend 100% UG | 99%- 75% UG | 74% - 50% UG | 49% - 25% UG | 24% - 0% UG

Example of a Reliability Comparison in the District of Columbia

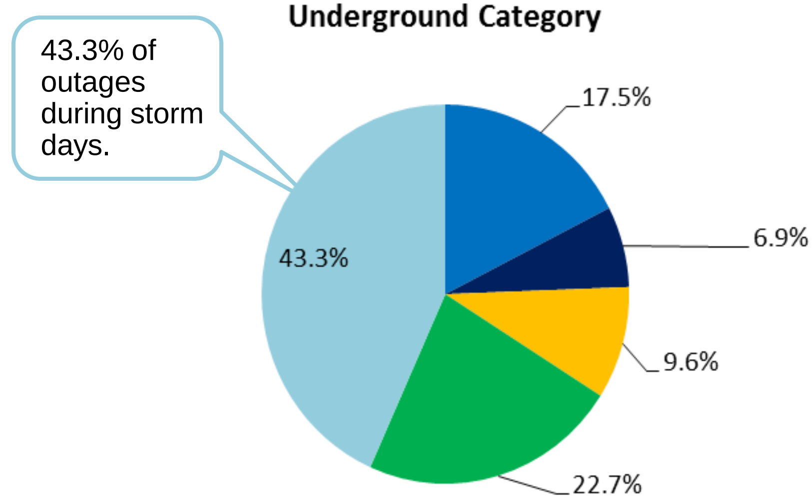
DC - % Feeders by Underground Category



DC - % Customers Served by Underground Category



DC - % Customers Affected (Storm Inclusive) by Underground Category



17% of feeders in DC are more then 75% overhead construction and account for 43% of the customer outages.

Legend 100% UG 99%- 75% UG 74% - 50% UG 49% - 25% UG 24% - 0% UG

Recommendations

Short Term:

- Establish a working group under the guidance of the Public Service Commission to review existing COMAR regulations to identify appropriate changes:
  - Existing language allows new or upgraded overhead lines to be built in existing overhead areas. Should future new or upgraded lines be underground?
  - If so, what size of project should be included?
  - Should existing lines be undergrounded when new lines are being built?
- Work with utilities as they perform selective underground projects to improve reliability and gain cost and reliability information, including key substation supply lines
- Evaluate and implement mechanisms for cost recovery of selective undergrounding and other system hardening programs

Long Term:

- Develop long term strategy, cost and reliability performance of a more expansive undergrounding program that would be appropriate for each utility
- Implement a long-term program to underground or harden supply lines into distribution substations to the extent that current operations or performance justifies the need
- Coordination of undergrounding projects in conjunction with timetables to renew/replace existing equipment, and governmental road and beautification projects

APPENDIX

Issues to be addressed in UG Study

pepco
A PHI Company

Core Areas		
Engineering Technical	Selection Criteria	• How are undergrounding sites selected and prioritized?
	Impact on Engineering	• How long does underground construction typically last? • What else is impacted during construction?
	Reliability	• What are the positive reliability impacts of undergrounding, for various categories of feeders.
	Impact on Planning	• Consolidation of Existing Plans • What are the impacts on future planning?
	Customer & Societal Impact	• What are benefits of underground service? • What are the disadvantages of underground service?
Legal	Governance and Administration	• What is the governance plan for undergrounding?
	Coordination of Future Plans with Other Utilities/ Pole Agreements	• What are the impacts on other pole users upon undergrounding of electric equipment?
Financial	Budget Impact	• How much would it cost to underground portions and even all overhead Pepco lines in Maryland?
	Funding	• What options exist for funding undergrounding efforts?
	Rate Impact	• How would costs be allocated to customers? What if only some customers desire more UG?

Analysis Structure

Undergrounding issues tend to fall into three analytical core areas:

Engineering Technical

- Decisions on which sections of overhead line to convert first; system configuration, restoration priorities, critical or least performing, underground districts.
- Impact to joint use pole attachments and owners
- Evaluation of design and construction standards
- Development of an immediate 3-5 year rolling plan as well as a long term-term view.
- Coordination with current and future enhancement programs
- Coordination of future plans with government and other utilities in MD (road, water, CATV, phone, sewer, beautification)
- The mechanism to account for adjusting the levels of spending to facilitate effective planning and coordination of construction

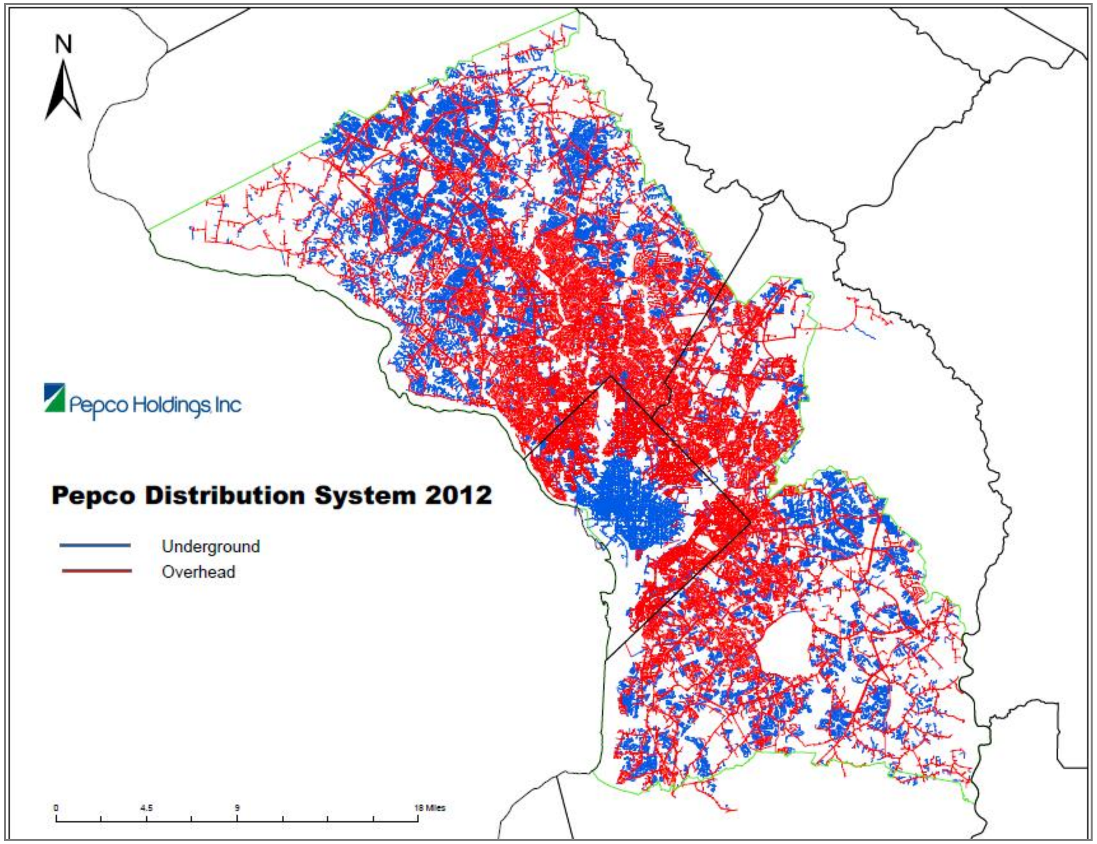
Legal/Regulatory

- Review current regulations on undergrounding and changes necessary to implement revised regulations
- Regulatory approval
- Coordination with current mandates (Governor's Executive Order)
- Governance and Administration
- Cost allocation & cost recovery

Financial

- Identification of funding options, tax, rate base and bonds.
- Recovery of non-depreciated overhead infrastructure

Pepco's MD Electric System Overview



Pepco MD System

- 6,210 miles of overhead lines (49%).
- 6,558 miles of underground lines (51%).
- 56% of customers are served by underground service.
- 44% of customers are served by overhead service.

Customers by Feeder

- 1.7% of customers are on 100% underground feeders.
- 19.6% of customers are on feeders that are >= 85% underground.
- 78.7% of customers are on mixed feeders.

State Roundtable Participants

Office of Governor O'Malley

Abigail Hopper
Energy Advisor, Office of Governor Martin O'Malley
Email: ahopper@gov.state.md.us

Matthew Raifman
StateStat Analyst, Office of Governor Martin O'Malley
Email: matthew.raifman@maryland.gov

Maryland Public Service Commission

Merwin Sands
Executive Director, Maryland Public Service Commission
Email: merwin.sands@maryland.gov

Jerry T. Hughes
Chief Engineer, Maryland Public Service Commission
Email: thughes@psc.state.md.us

Maryland Energy Administration

Malcolm Woolf
Director, Maryland Energy Administration
Email: mwoolf@energy.state.md.us

Kevin Lucas
Director Energy Market Strategies, Maryland Energy Administration
Email: klucas@energy.state.md.us

David St. Jean
Planning Manager, Energy Assurance, Maryland Energy Administration
Email: dstjean@energy.state.md.us

David Beugelmans
Clean Energy Program Manager, Maryland Energy Administration
Email: dbeugelmans@energy.state.md.us

Maryland Department of Natural Resources

John Griffin
Secretary of Natural Resources, Maryland Department of Natural Resources
Email: jgriffin@dnr.state.md.us

Pete Dunbar
Director, Maryland Department of Natural Resources, Power Plant Research Program
Email: pdunbar@dnr.state.md.us

Sandi Patty
Maryland Department of Natural Resources, Power Plant Research Program
Email: spatty@dnr.state.md.us

Maryland Emergency Management Agency

Ken Mallette
Executive Director, Maryland Emergency Management Agency
Email: ken.mallette@maryland.gov

Michael Fischer
Director of Operations, Maryland Emergency Management Agency
Email: michael.fischer@maryland.gov

Maryland Department of Information Technology

Barney Krucoff
State Geographic Information Officer, Maryland Department of Information Technology
Email: bkrucoff@maryland.gov

Ken Miller
Deputy State Geographic Information Officer, Maryland Department of Information Technology
Email: ken.miller@maryland.gov